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Date of Hearing: 6-8-12

Case No. 12-1230-EL-SSO

PUCO Case Caption: In the Matter of the Application of Ohio Edison, the Cleveland Electric Illuminating Company and the Toledo Edison Company.

List of exhibits being filed:

Company Exbt 14A
AEPR 3
AEPR 4
OCC 14
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OCC 16

Reporter's Signature: Karen Sue Gibson
Date Submitted: 6-8-12

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BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

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In the Matter of: The Application of The Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R. C. Section 4928.143 in the Form of an Electric Security Plan.	Case No. 12-1230-EL-SSO

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PROCEEDINGS

before Mr. Gregory Price and Ms. Mandy L. Willey, Hearing Examiners, at the Public Utilities Commission of Ohio, 180 East Broad Street, Room 11-C, Columbus, Ohio, on June 8, 2012, called at 9:00 a.m.

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VOLUME IV - Rebuttal

\- - -

ARMSTRONG & OKEY, INC.
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FE-14A

Exhibit RBS-1

Robert B. Stoddard

Vice President and
Practice Leader, Energy & Environment

MA and MPhil Economics
Yale University

BA Economics and Music
summa cum laude
Amherst College

Vice President Robert Stoddard heads CRA's Energy & Environment Practice. He has over twenty years of experience assisting clients in defining, analyzing, and interpreting the economic issues involved with competition and product valuation in energy and other markets. His recent work has focused on electricity industry restructuring and on providing both strategic analyses and testimony for utilities, generation owners, and governments regarding the practical implications of market design and structure, particularly in New York, New England, and PJM. He has submitted testimony to the Federal Energy Regulatory Commission as well as to the utility commissions and legislatures of several states on competitive market design and market power issues, and he as testified in civil litigation and arbitration on the interpretation of, and damages relating to, energy contracts. He recently was the lead economist for capacity suppliers in developing the New England capacity market, played a central role in negotiating the settlement of the PJM Reliability Pricing Model, and developed the leading proposal for the design of a capacity market for California. In related areas, Mr. Stoddard has served as the special economic counsel to the Rhode Island House of Representatives for electricity restructuring and acted as overseer for Connecticut's standard offer energy auction; devised an energy trading strategy audit and strategy redesign for a major northeastern utility; conducted a comprehensive review of operating flaws within the structure of an ISO; designed a market-based transfer pricing system for the distribution, trading, and generation subsidiaries of a leading western utility; and managed the federal and state regulatory filings for several large utility mergers and asset sales.

Clients

Mr. Stoddard has been a consultant on electric market issues to a wide range of energy market stakeholders including ArcLight Capital Management, AES, American Wind Energy Association, Astoria Generating, Bangor Hydro Electric, California Independent System Operator, Citibank, City of New York, Connecticut Department of Public Utility Control, Consolidated Edison Co. of New York, Constellation Energy Commodities Group, CSG Investments, Dayton Power & Light, Devon Canada, Dominion, Duke Energy, Edison Mission Energy, EdF, Electricity Supply Board of Ireland, Emera, Energia dos Portugal, Energy Capital Partners, Energy East, Entergy Nuclear, FirstEnergy, FirstLight, GenOn, Hydro Québec, Independent Energy Producers Association, International Power, J. Aron & Company, Maine Energy Recovery Co., Maine Public Service, Midlands Cogeneration Venture, Morgan Stanley Capital Group, Morris Energy Group, New England Power Generators Association, New York City Economic Development Corporation, New York Energy Buyers Forum, NextEra Energy Resources, North American Energy Alliance, Northeast Utilities, NRG Energy, Orange & Rockland Utilities, Pepco Energy Services, Pinnacle West, PJM Power Providers, Portland General Electric, Powerex Corporation, Rhode Island Speaker and the House of Representatives, San Diego Gas & Electric, Southern California Edison, Sunoco, Tenaska, Tonbridge Power, USGen New England, USPowerGen, and Williams Power.

Strategy

- Led creation of business model and market-entry strategy for company developing an innovative renewable power technology.
- Led creation of business model and business plan for a combined wind-farm / transmission company in Canada.
- Assisted major utility in strategic and tactical plan to support transfer between Regional Transmission Organizations, providing both analytic and regulatory advisory support.
- Directed the development of the master energy infrastructure strategy for the City of New York, working with key stakeholders to develop a strategy to develop the infrastructure needed to meet the city's future energy needs economically and reliably.
- Developing a detailed forecasting model for capacity prices in PJM resulting from the new capacity market design and, using this information, worked with a major market participant's strategy and financing staff to identify under-valued assets for acquisition.
- With senior management of a major utility, developing a transmission investment strategy to reflect shifting competitive opportunities, RTO market design, and state and federal regulation. Identifying of key opportunities to leverage and redirect capital expenditures to significantly decrease cost of delivered power and increase rate of return to corporate shareholders.
- Developing a competitive bidding strategy for a complex hydroelectric generation asset to recognize opportunity costs, limitations of market rules, and effects of key transmission constraints in a two-settlement, locational pricing regime.
- Assisting a leading provider of utility outsourcing services to develop a comprehensive regulatory strategy for its service offerings to a major utility.

Electricity contracts and project valuation

- Testimony (in progress) to support the tax valuation of independent power production facilities in New York and Maryland, evaluating the free cash flows from sales of energy and other products' net of fuel, emissions, and other relevant costs.
- Testimony successfully supporting claims against industrial customer in breach-of-contract claims by a retail energy provider.
- Testimony supporting the cost-effectiveness of a long-term power purchase agreement between Cape Wind and National Grid in furtherance of Massachusetts policy goals.
- Testimony regarding the market value of a nuclear power facility excluding idiosyncratic nuclear risks using a comparable transactions analysis.
- Expert testimony supporting the reliability must-run (RMR) applications of over 2 GW of generation in New England, documenting need for RMR contracts to maintain the financial viability of needed resources. The case resulted in a settlement agreement that provided for significant support payments for these resources during the transition to compensatory market payments.

- Testimony for a bankruptcy court regarding damages arising from a power purchase agreement that had been rejected at the time of bankruptcy.
- Testimony in arbitration proceedings to determine the product specification and price of the capacity product contracted for in a period of regulatory change.
- Support of project financials for major purchase of New York City generation to investor community.
- Testimony in arbitration proceedings about the interpretation of, and damages owed under, the electricity section of a contract for the purchase of a large petrochemical refinery and resale of the refinery's output.
- State-appointed auditor of Connecticut's utilities' first Standard Offer power procurement auction, reviewing reasonableness of pricing and the terms and conditions of contract offers to supply essentially all of the state's power needs for a three-year period.
- Testimony on fuel costs adders reasonably allowable in a long-term power contract between NRG and Connecticut Light & Power and attendant retail rate design to fairly allocate the incremental costs.
- Assisting Consolidated Edison Co. of New York negotiate the sale of its nuclear facilities and linked buyback of power for the license life of the units.
- Working with Pinnacle West staff to develop options-based contracts to transfer power between its generating, trading, and distribution affiliates to preserve appropriate performance incentives.
- Project manager for bankruptcy evaluation of a New England cooperative, involving assessment of value of hydroelectric, nuclear assets, and long-term contracts.

Electricity market design

- Project director and testifying expert for capacity market design litigation and settlement negotiations for the New England and PJM markets, representing coalitions of the major generation owners in the region.
- Principal author of SDG&E and California Forward Capacity Market Advocates' proposal for a centralized capacity market structure to address resource adequacy needs of the California electricity markets. Subsequently offered a market-based approach to backstop capacity pricing in California on behalf of NRG Energy and the Independent Energy Producers Association.
- Working with other CRA experts, prepared a white paper on capacity market design for Energia dos Portugal.
- Principle drafter of the current form of the utility restructuring laws in Rhode Island, implementing improved retail market access.
- Project director for a major policy initiative by a major generation owner to review key flaws in modern RTO design that distort competitive pricing and outcomes.

- Project manager and testifying expert for litigation regarding the market rules governing use of phase angle regulators between New York and PJM. Subsequently, assisting the negotiated design of these rules pursuant to the FERC orders.
- In the redesign of the wholesale power market for the Republic of Ireland, responsible for development of rules regarding demand-side integration, interconnection management, financial transmission rights, and transmission loss representation.
- Testifying expert on behalf of a major importer into the California electricity market on the allocation of financial transmission rights across external interties.
- Project director for a review for the California Independent System Operator of transmission rights allocations in the proposed California wholesale market.

Market power analysis and mitigation

- Testifying expert successfully defending against charges of market manipulation by largest capacity importer to New England.
- Led preparation of report successfully defending against charges of market manipulation by a power marketer scheduling transactions through multiple jurisdictions.
- Lead expert defending a major financial institution against charges of manipulating ICE index markets (ongoing).
- Lead economist in team developing alternative mitigation measures for buyer-side market power in the New England capacity market.
- Testified on appropriate metrics for market power in PJM energy and capacity markets.
- Testifying expert and project director supporting the integration of Virginia Electric and Power (Dominion) into the PJM marketplace.
- Project manager for an acquisition of generation assets in Connecticut by a competing supplier, using detailed hourly analyses of power flows and potential future competition, and presenting the results to the FERC, US Department of Justice, and the Connecticut Office of the Attorney General.
- Project manager for a market power analyses needed to obtain federal and state regulatory approval of the merger of the leading natural gas transporter and distributor in the eastern US with a vertically integrated utility with substantial gas holdings.
- Project manager for study of the potential competitive effects of the divestiture of substantially all the New York City utility generation to independent power producers, including detailed behavioral modeling that took account of the complex transmission system and design of market power mitigation measures for the energy and capacity markets.

Articles

With Edward L. Kim, Richard D. Tabors and Todd E. Allmendinger, "Carbitrage: Utility Integration of Electric Vehicles and the Smart Grid," *Electricity Journal*, Vol. 25 No. 2, March 2012, pp.16–23.

Testimony and reports

"Update to the Analysis of the Impact of Cape Wind on Lowering New England Energy Prices," CRA report authored by Robert B. Stoddard, on behalf of Cape Wind Associates, LLC, filed in *Petition of NSTAR Electric Company for Approval of a Proposed Long-Term Contract for Renewable Energy with Cape Wind Associates, LLC Pursuant to St. 2008, c. 169, § 83*, March 2012.

FirstEnergy Solutions Corp. & Allegheny Energy Supply Company, L.L.C. v PJM Interconnection, L.L.C., FERC Docket EL12-50-000. Affidavit in support of complaint seeking to require allocation of partial-year Auction Revenue Rights, March 2012.

California Independent System Operator, Inc., FERC Docket No. ER12-897-000. Affidavit in support of protest by NRG Energy, Inc. of proposed waiver of provisions of the Capacity Procurement Mechanism, February 2012.

FirstEnergy Solutions Corp. & Allegheny Energy Supply Company, L.L.C. v PJM Interconnection, L.L.C., FERC Docket EL12-19-000. Affidavit in support of complaint seeking to fund Financial Transmission Rights solely from Day-Ahead Market settlement surplus, December 2011.

"Resource Adequacy in Ohio's Restructured Market," CRA report authored by Robert B. Stoddard, on behalf of Duke Energy Ohio, December 2011.

Bangor Hydro Electric Company and Maine Public Service Company Request for Exemptions and Reorganization Approvals, Maine Public Utilities Commission Docket No. 2011-170. Rebuttal testimony on behalf of Emera regarding potential horizontal and vertical market power issues of proposed acquisitions, September 2011; live testimony, December 2011, March 2012.

PJM Interconnection, L.L.C., Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc., FERC Docket No. ER12-91-000. Affidavit on behalf of Duke providing cost-benefit analysis of its proposed transition from MISO to PJM in support of inclusion of transition costs in transmission rates, October 2011; rebuttal affidavit, November 2011.

In the Matter of Portland General Electric Company 2012 Annual Power Cost Update Tariff (Schedule 125), Oregon Public Utilities Commission Docket No. UE-228. Rebuttal testimony on behalf of Portland General Electric assessing reasonableness of its mid-term hedging strategy for gas and electricity procurement, August 2011.

California Independent System Operator Corporation, FERC Docket No. ER11-2256. Affidavit on behalf of the Independent Energy Producers Association protesting flawed elements of the Capacity Procurement Mechanism, December 2010; presentation to FERC Technical Conference, March 2011.

Expert Report on behalf of Mirant Mid-Atlantic, LLC, Maryland Tax Court Case Nos. 09-RP-CH-261-265; 09-RP-CH-280-294; and 09-RP-CH-294-298, July 2010; live testimony, February 2011.

PJM Interconnection, LLC, FERC Docket No. ER11-2288. Affidavit on behalf of GenOn Energy Management, LLC and Edison Mission Energy protesting the creation of a summer-only demand resource capacity product and the continuation of a limited demand resource capacity product in the PJM Reliability Pricing Model, December 2010.

Testimony on behalf of the PJM Power Providers before the Maryland Public Service Commission in Administrative Docket PC22 regarding the PJM Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results, October 2010.

ISO New England Inc. and New England Power Pool, FERC Docket No. ER10-787-000, and *New England Power Generators Association v. ISO New England, Inc.*, FERC Docket No. EL10-50-000 (combined). Affidavit on behalf of New England Power Generators Association supporting need for revisions to Forward Capacity Market design, March 2010. Rebuttal affidavit, April 2010. Pre-filed testimony, July 2010; supplemental affidavits, September 2010.

Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid for Approval of Proposed Long-Term Contracts for Renewable Energy with Cape Wind Associates, LLC Pursuant to St. 2008, c. 169, § 83, Massachusetts D.P.U. Docket No. 10-54. Direct testimony on behalf of Cape Wind Associates, LLC, June 2010.

Richard Blumenthal, Attorney General for The State of Connecticut v. ISO New England Inc., Brookfield Energy Marketing Inc., et al. FERC Docket No. EL09-47-000, and *The Connecticut Department of Public Utility Control and the Connecticut Office of Consumer Counsel v. ISO New England Inc., Brookfield Energy Marketing Inc., et al.*, FERC Docket No. EL09-48-000. Prefiled testimony on behalf of Brookfield Energy Marketing Inc. regarding scheduling of capacity imports. June 2009. Answering testimony, February 2010.

Pepco Energy Services, Inc. v. Constellation Energy Commodities Group, Inc. (ad hoc arbitration); expert report on behalf of Constellation on alleged mis-payment under a bilateral contract for PJM capacity, April 2008; testimony, October 2009.

Application of MidAmerican Energy Company for the Determination of Ratemaking Principles, IUB Docket No. RPU-2009-0003. Rebuttal testimony on behalf of NextEra Energy Resources, June 2009; surrebuttal testimony, July 2009, live testimony, August 2009.

Midwest Independent Transmission System Operator Inc., FERC Docket Nos. ER08-394-007 and -009. Affidavit regarding monitoring and mitigation of resource adequacy auctions on behalf of Duke Energy Corp., July 2009.

Calpine Corporation, Citigroup Energy Inc., Dynegy Power Marketing, Inc., J.P. Morgan Ventures Energy Corporation, BE CA, LLC, Mirant Energy Trading, LLC, NRG Energy, Inc., Powerex Corporation, and RRI Energy, Inc. v. California Independent System Operator Corp., FERC Docket No. EL09-62-000. Affidavit on behalf of complainants, June 2009; reply affidavit, July 2009.

Report on ISO New England Internal Market Monitoring Unit Review of the Forward Capacity Market Auction Results and Design Elements, prepared for New England Power Generators Association, Inc. and filed in *ISO New England, Inc.*, FERC Docket No. ER09-1282-000 (June 2009).

Richard Blumenthal, Attorney General for Connecticut, v. ISO New England Inc. et al., FERC Docket Nos. EL09-47-000 and EL09-48-000. Prefiled testimony on behalf of Brookfield Energy Marketing Inc. regarding scheduling of capacity imports, June 2009.

Master Transmission Plan for New York City, report prepared for the New York City Economic Development Corporation, April 2009.

California Independent System Operator Corporation, FERC Docket No. ER09-589-000. Affidavit on behalf of Powerex Corp. regarding changes to the CAISO credit policy regarding unsecured credit, February 2009.

"Contracting and Investment: A Cross-Industry Assessment" report filed with Post-Conference Comments of Reliant Energy, Inc., *Credit and Capital Issues Affecting the Electric Power Industry*, FERC Docket No. AD09-002-000, January 2009.

PJM Interconnection, LLC FERC Docket No. ER09-412-000. Affidavit and reply affidavit on behalf of Mirant, Edison Mission Energy, International Power, and FPL (NextEra Energy Resources) regarding omnibus changes to the PJM RPM capacity market tariff, January 2009.

Midwest Independent System Transmission Operator, Inc. FERC Docket Nos. ER08-394-000, -003, -007. Affidavit on behalf of Duke Energy protesting the market monitoring standards proposed for the voluntary capacity auction in Midwest ISO, January 2009.

Devon Canada Corp. et al. v. Pittsfield Generating Company LP et al. Expert report for defendant regarding damages from alleged breach of natural gas supply contract to a reliability must-run electric generator, December 2008.

Maryland Public Service Commission v. PJM Interconnection, LLC, FERC Docket Nos. EL08-34-000 and EL08-47-000. Affidavit on behalf on Mirant Parties on appropriate structural and behavioral market power tests in PJM, October 2008; reply affidavit, November 2008.

ISO New England, Inc., FERC Docket No. ER08-1209-000. Affidavit on behalf of the New England Power Generation Association on compensation to reliability resources, July 2008; reply affidavit, September 2008.

Midwest Independent Transmission System Operator, Inc. FERC Docket No. ER08-1169-000. Affidavit on behalf of FPL Energy, LLC, regarding revisions to Generation Interconnection Procedures, July 2008.

RPM Buyers v. PJM Interconnection, LLC, FERC Docket No. EL08-67-000. Affidavit on behalf of PJM Power Providers opposing *ex post* changes to initial RPM auction results, June 2008.

Assessment of Maine's Continued Participation in ISO New England and Alternatives, Expert report in Maine Public Utilities Commission Docket No. 2008-156, prepared on behalf of Bangor Hydro-Electric Company, June 2008; testimony to the MPUC, October 2008.

"Reliability at Stake: PJM's Reliability Pricing Model" report prepared for PJM Power Providers in conjunction with FERC technical conference to discuss the operation of forward capacity markets in New England and the PJM region, FERC Docket No. AD08-4-000, May 2008.

Estimation of Indian Point 2 Fair Market Value Using a Statistical Analysis of Comparable Transactions, Testimony in *Consolidated. Edison Co. of New York v. United States*, No. 04-0033C (Fed.Cl.), February 2008.

Critique of the APPA/CMU Study "Do RTOs Promote Renewables?" (with David Riker) commissioned by Electric Power Supply Association, January 2008.

Midwest Independent Transmission System Operator, Inc. Electric Tariff Failing Regarding Resource Adequacy, FERC Docket No. ER08-394-000. Affidavit on behalf of Duke Energy Corp. and FirstEnergy Services Co. on the urgency of implementing a uniform resource adequacy requirement, January 2008.

Mirant Energy Trading, LLC, et al. v PJM Interconnection, LLC, FERC Docket No. EL08-8-000. Affidavit on the flaws in the market power mitigation rules for the Third Incremental Auction of the PJM Reliability Pricing Model capacity market., November 2007.

Wholesale Competition in Regions with Organized Electric Markets, FERC Docket Nos. RM07-19-000 and AD07-7-000. Affidavit on role of demand-side resources in organized electric markets on behalf of Duke Energy Corp., September 2007.

Order Instituting Rulemaking to Consider Refinements to and Further Development of the Commission's Resource Adequacy Requirements Program, California PUC Rulemaking 05-12-013. Principal author of SDG&E Track 2 Resource Adequacy Program Proposal, March 2007; principal author, "Joint Pre-Workshop Comments of the California Forward Capacity Market Advocates," May 2007, and "Proposal for a Forward California Capacity Market," August 2007.

People of the State of Illinois, ex rel. Illinois Attorney General Lisa Madigan v. Exelon Generating Co., LLC et al., FERC Docket No. EL07-47-000. Affidavit assessing reasonableness of outcomes in the Illinois power procurement auction on behalf of J. Aron & Company and Morgan Stanley Capital Group, July 2007.

PJM Interconnection, LLC, FERC Docket Nos. EL03-236-000 *et al.* Affidavit regarding three-pivotal-supplier market power test and scarcity pricing in PJM's energy markets on behalf of Mirant Energy Trading et al., May 2007.

Midwest Independent Transmission System Operator, FERC Docket No. ER07-550-000. Affidavit regarding resource adequacy issues in ancillary services market design on behalf of Duke Energy Co., March 2007.

PJM Interconnection LLC, FERC Docket No. EL05-148-000 *et al.* Affidavit regarding redesign of the long-run resource adequacy market in PJM on behalf of the Mirant Parties, October 2005; supplemental affidavit on behalf of the Mirant Parties, NRG and Williams Power Co., November 2005; presentation to FERC Technical Conference, February 2006; prefiled comments to FERC Technical Conference Panel 1, May 2006, on behalf of the Mirant Parties, Williams Power Co., and Dayton Power & Light; prefiled comments to FERC Technical Conference Panel 2, May 2006, on behalf of the Mirant Parties; supplemental affidavit on behalf of the Mirant Parties, June 2006; affidavit and reply affidavit supporting settlement agreement, September and October 2006.

Mystic Development, LLC, FERC Docket No. ER06-427-000. Affidavit analyzing future revenues in support of RMR filing, December 2005; supplemental affidavit, September 2006.

In re USGen New England, Inc. Debtor. United States Bankruptcy Court for the District of Maryland, Case No. 03-30465. Expert report on damage resulting from PPA rejection on behalf of USGen New England, March 2006; supplemental report, September 2006.

California Independent System Operator Corporation, FERC Docket No. ER06-615-000. Joint affidavit with Paul Kevin Wellenius regarding FTR allocations under new CAISO market design on behalf of Powerex Corp, June 2006

Fore River Development, LLC, FERC Docket No. ER06-822-000. Affidavit analyzing future revenues in support of RMR filing, December 2005.

Assessment of the New York City Electricity Market and Astoria, Gowanus, and Narrows Generating Stations. Report prepared for Morgan Stanley Senior Funding, Inc. related to financing for US Power Generating Co. and Madison Dearborn Capital Partners IV, L.P., January 2006.

Review of Initial Execution of Protocol for Implementation of Commission Order No. 476. Report to FERC in Docket EL02-23-000, regarding operation of controllable lines between NYISO and PJM, on behalf of Con Edison, September and December 2005.

Honeywell International Inc. v. Sunoco, Inc. AAA Case No. 13 181 Y 02588 04. Expert report, deposition and live testimony on contract energy pricing in petrochemicals, May 2005.

Con Edison Energy, Inc. v. ISO New England, Inc. and New England Power Pool, FERC Docket No. EL05-61-000. Affidavit on behalf of complainant regarding bidding rules in capacity deficiency auction, February 2005.

KeySpan Ravenswood LLC v. New York Independent System Operator, Inc., FERC Docket No. EL05-17-000. Affidavit on behalf of Consolidated Edison Company of New York, Inc. regarding retroactive damage claims from a capacity market, November 2004.

Devon Power LLC et al., FERC Docket No. ER03-563-030. Affidavit and rebuttal affidavit regarding design of locational installed capacity markets on behalf of FPL Energy, April and May 2004; answering testimony on behalf of Capacity Suppliers, November 2004; cross-answering testimony, December 2004; supplemental cross-answering testimony, January 2005; deposition and hearing testimony, February to March 2005; affidavit supporting Settlement Agreement, March 2006.

Application of Dominion North Carolina Power to Join PJM as PJM South, North Carolina Utilities Commission, Case No. E-22 SUB 418. Direct testimony and cost-benefit study on behalf of applicant, April 2004; rebuttal testimony, December 2004; examination, January 2005.

Application of Virginia Electric and Power Company to Join PJM as PJM South, State Corporation Commission of Virginia Case No. PUE-2000-00551; direct testimony and cost-benefit study on behalf of applicant, June 2003; supplemental direct testimony, March 2004; rebuttal testimony, September 2004; examination, October 2004.

Consolidated Edison v. Public Service Electric and Gas Co. et al., FERC Docket No. EL02-23-000 (Phase II); direct testimony on behalf of Consolidated Edison Company of New York, Inc., June 2002 regarding transmission facilities contracts. Remand testimony, January to March 2003.

In the Matter of the Siting of Electric Transmission Facilities Proposed to be Located at the West 49th Street Substation of Consolidated Edison Company of New York, Inc. et al., New York State Public Service Commission Case Nos. 02-M-0132, 01-T-1474, 02-T-0036, 02-T-0061; testimony on behalf of Consolidated Edison Company of New York, Inc., April 2002 (direct) and May 2002 (rebuttal).

Testimony before the Rhode Island Special Legislative Commission on the Quonset-Davisville Steamplant, January and April 2002.

Testimony before the Committee on Corporations, Rhode Island House of Representatives, regarding 2002 House Bill 7786, *An Act Relating to Public Utilities and Carriers,* April 2002.

Keyspan-Ravenswood, Inc. v. New York Independent System Operator, FERC Docket No. EL02-59-000, direct testimony on behalf of Consolidated Edison Company of New York, Inc. regarding implementation of market power mitigation in installed capacity markets, March 2002.

DPUC Investigation Into Viability of Power Supply Contracts to the Connecticut Light and Power Company and the United Illuminating Company, Connecticut DPUC Docket No. 01-12-05, direct testimony on behalf of NRG Energy, Inc. and affiliates, February 2002.

Joint Study by the Department of Public Utility Control and the Office of the Consumer Counsel Regarding Electric Deregulation and How Best to Provide Electric Default Service After January 1, 2004, Connecticut DPUC Docket No. 01-12-06, direct testimony on behalf of NRG Energy, Inc. and affiliates, January 2002.

The Narragansett Electric Co. Rate Changes for January 1, 2002, Rhode Island PUC Docket No. 3402, direct testimony on behalf of the Hon. John B. Harwood, Speaker of the House of Representatives, State of Rhode Island and Providence Plantations, December 2001.

Wisvest-Connecticut, LLC et al., FERC Docket No. EC01-70-000, technical conference presentation on behalf of NRG Energy, Inc. and affiliates, September 2001.

New York Independent System Operator, Inc., FERC Docket No. ER01-2536-000, affidavit on behalf of Consolidated Edison Co. of New York, the City of New York, the New York Energy Buyers Forum, and the Association for Energy Affordability, Inc., July 2001.

Testimony before the Committee on Corporations, Rhode Island House of Representatives regarding electricity restructuring; various dates, 2001.

Consolidated Edison Co. of New York, Inc., FERC Docket Nos. EL01-45-000 and ER01-1385-000, affidavit and rebuttal affidavit (joint with William H. Hieronymus) on behalf of Consolidated Edison Co. of New York, March and April, 2001.

Joint Petition of Consolidated Edison Co. of New York, Inc. and Entergy Nuclear Indian Point 2, LLC, for Authority to Transfer Certain Generating and Related Assets and for Related Relief, NYSPSC Case 01-E-0040, technical conference presentation on behalf of applicants, February 2001.

Professional history

2009–Present	*Vice President and Practice Leader*, Charles River Associates, Boston, MA
2003–2009	*Vice President*, Charles River Associates, Boston, MA
2001–2003	*Principal*, Charles River Associates, Boston, MA
1995–2001	*Managing Consultant*, PA Consulting Group, Cambridge, MA PA purchased PHB Hagler Bailly, formed by the merger of Hagler Bailly and Putnam, Hayes & Bartlett, where Mr. Stoddard had been a Principal.

1993–1995	*Senior Health Economist and Acting Managing Director*, Benefit Research USA, a Quintiles company, Cambridge, MA
1990–1993	*Senior Associate*, Charles River Associates, Boston, MA
1985–1990	*Teaching and Research Fellow*, Department of Economics, Yale University
1983–1985	*Assistant Economist*, Federal Reserve Bank of New York

Education

1990	M.Phil., Economics, Yale University
1986	M.A., Economics, Yale University
1983	B.A. *summa cum laude*, Amherst College; Phi Beta Kappa
1979	Diploma, Westerville (OH) South High School

AEPR-3

Capacity Pricing for Load in ATSI Zone

Based on PJM Planning Year 2015/16 Base Residual Auction Results

Zone	Preliminary Zonal Capacity Price [$/MW-day]	Base Zonal RPM Scaling Factor	Forecast Pool Requirement (FPR)	Capacity Price for Load (not Loss adjusted)	Loss Factor	Capacity Price for Load (adjusted for Losses)
(1)	(2)	(3)	(4)	(5)=(2)x(3)x(4)	(6)	(7)=(5)x(6)
ATSI	$294.03	1.06391	1.0859	**$339.69**	1.028658	**$349.43**

Notes/Sources

1. Columns (2), (3) and (4) from PJM website www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item09
   File Name: *20120518-2015-2016-base-residual-auction-results.xls*
2. Column (6) from *PJM Open Access Transmisson Tariff, Attachment H-21, paragraph 3* : 2.786%
   Loss Factor: 1 /(1 - 0.02786) = 1.028658

AEPR-4

2015/2016 DY BRA Load Pricing Results

RPM Parameters	
IRM	15.4%
Pool Average EFORd	5.90%
FPR	1.0859
RTO Reliability Requirement [MW]	162,777.4
Short-Term Resource Target [%]	2.5%
Short-Term Resource Target [MW]	4069.4
Obligation Peak Load Scaling Factor	1.01096

LDA Capacity Price Components

LDA	LDA Base UCAP Obligation [MW]	System Marginal Price [$/MW-day]	Locational Price Adder* Applicable to LDA [$/MW-day]	Costs due to Extended Summer Resource Price Adder in constrained LDA [$/day]	Component due to Extended Summer Price Adder [$/MW-day]	Costs due to Annual Resource Price Adder in constrained LDA [$/day]	Component due to Annual Resource Price Adder [$/MW-day]	Component due to Make-Whole [$/MW-day]	LDA Capacity Price [$/MW-day]
RTO	168,630.6	$118.54	$0.00	$2,711,782.44	$16.08	$0.00	$0.00	$0.001	**$134.62**
MAAC	68,742.2	$118.54	$31.46	$0.00	$16.08	$0.00	$0.00	$0.001	**$166.08**
EMAAC	37,440.5	$118.54	$31.46	$0.00	$16.08	$0.00	$0.00	$0.001	**$166.08**
SWMAAC	15,919.1	$118.54	$31.46	$0.00	$16.08	$0.00	$0.00	$0.001	**$166.08**
PEPCO	7,709.3	$118.54	$31.46	$0.00	$16.08	$0.00	$0.00	$0.001	**$166.08**
ATSI	14,940.4	$118.54	$186.08	$0.00	$16.08	$322,189.38	$21.56	$0.037	**$342.30**

*Locational Price Adder with respect to RTO

Calculation of Zonal Capacity Prices for PS and DPL

Sub-Zone/Zone	LDA Capacity Price in EMAAC [MW]	Cleared Capacity [MW]	Additional Locational Price Adder with respect to EMAAC [$/MW-day]	Additional Costs due to Extended Resource Price Adder with respect to EMAAC [$/day]	Additional Component due to Extended Resource Price Adder with respect to EMAAC [$/MW-day]	Additional Costs due to Annual Resource Price Adder with respect to EMAAC [$/day]	Additional Component due to Annual Resource Price Adder with respect to EMAAC [$/MW-day]	Additional Make-whole Costs with respect to EMAAC [$/day]	Additional Component due to Make-whole with respect to EMAAC [$/MW-day]	Preliminary Zonal Capacity Price [$/MW-day]
Rest of PS		3,088.6	$0.00	$0.00		$0.00		$0.00		
PSNORTH		3,641.2	$0.00	$0.00		$0.00		$0.00		
PS	$166.08	6,729.8	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$166.08
Rest of DPL		3,114.1	$0.00	$0.00		$0.00		$0.00		
DPLSOUTH		1,722.1	$0.00	$0.00		$0.00		$0.00		
DPL	$166.08	4,836.2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$166.08

[redacted]

Zone	LDA1	LDA2	LDA3	2011 W/N Coincident Peak Load [MW]	Zonal Forecast Peak Load Scaling Factor	2015/2016 Prelim. Zonal Peak Load Forecast [MW]	Short-Term Resource Procurement Target [MW]	Obligation Peak Load Scaling Factor	Base Zonal RPM Scaling Factor	Base Zonal UCAP Obligation [MW]	[redacted]
AE	MAAC	EMAAC		2,520.0	1.08532	2,735.0	74.2	1.01096	1.09721	3,076.7	
AEP **				10,884.3	1.06817	11,626.3	315.6	1.01096	1.07988	13,079.0	
APS				8,210.0	1.06614	8,753.0	237.6	1.01096	1.07782	9,846.7	
ATSI			ATSI	12,620.0	1.05238	13,281.0	360.5	1.01096	1.06391	14,940.4	
BGE	MAAC	SWMAAC		6,960.0	1.04856	7,298.0	198.1	1.01096	1.06005	8,209.9	
COMED				21,480.0	1.09697	23,563.0	639.7	1.01096	1.10900	26,507.1	
DAYTON				3,180.0	1.10000	3,498.0	95.0	1.01096	1.11205	3,935.1	
DEOK **				4,413.7	1.07905	4,762.6	129.3	1.01096	1.09087	5,357.7	
DLCO				2,800.0	1.06036	2,969.0	80.6	1.01096	1.07198	3,340.0	
DOM				18,530.0	1.09773	20,341.0	552.2	1.01096	1.10976	22,882.6	
DPL	MAAC	EMAAC	DPL	3,920.0	1.06505	4,175.0	113.3	1.01096	1.07672	4,696.7	
JCPL	MAAC	EMAAC		5,960.0	1.06527	6,349.0	172.4	1.01096	1.07694	7,142.3	
METED	MAAC			2,800.0	1.09321	3,061.0	83.1	1.01096	1.10519	3,443.5	
PECO	MAAC	EMAAC		8,370.0	1.07252	8,977.0	243.7	1.01096	1.08427	10,098.7	
PENLC	MAAC			2,720.0	1.11360	3,029.0	82.2	1.01096	1.12581	3,407.5	
PEPCO	MAAC	SWMAAC	PEPCO	6,600.0	1.03833	6,853.0	186.0	1.01096	1.04971	7,709.3	
PL	MAAC			7,065.0	1.07346	7,584.0	205.9	1.01096	1.08522	8,531.6	
PS	MAAC	EMAAC	PS	10,150.0	1.04670	10,624.0	288.4	1.01096	1.05817	11,951.4	
RECO	MAAC	EMAAC		400.0	1.05500	422.0	11.5	1.01096	1.06656	474.7	
Notes:				**139,583.0**		**149,900.9**	**4,069.4**			**168,630.6**	

*** Obligation affected by FRR quantities*

The load charges for Base Zonal UCAP Obligations at the Preliminary Zonal Capacity Prices exceed the sum of Resource Credits, Make-Whole Payments, QTU Credits and CTR/ICTR Credits as the Base Zonal UCAP Obligations include uncleared Short-Term Resource Procurement Target with no Resource Credits.

PJM OPEN ACCESS

TRANSMISSION TARIFF

Effective Date: 6/4/2012

ATTACHMENT H-21

Annual Transmission Rates -- American Transmission Systems, Incorporated for Network Integration Transmission Service

1. The Annual Transmission Revenue Requirements ("ATRR") and the rates for Network Integration Transmission Service are equal to the results of the formula shown in Attachment H-21A, and will be posted on the PJM website. The ATRR and the rates reflect the cost of providing transmission service over the 69 kV and higher transmission facilities of American Transmission Systems, Inc. ("ATSI"), as specified in paragraphs 2, 6 and 7. Service utilizing other ATSI facilities will be provided at rates determined on a case-by-case basis and stated in service agreements with affected customers.

2. Network Customers with load in the ATSI Zone shall pay rates differentiated by voltage level. Network Customers with load in the ATSI Zone shall pay the 138 kV and above transmission service rate. Network Customers with load in the ATSI Zone shall also pay the below 138 kV transmission service rate for their load that is served or deemed to be served by transmission facilities below 138 kV. In order to conduct settlements for transmission service in the ATSI Zone, the procedures outlined below will apply. An example calculation is provided in Attachment H-21A, Appendix B.

    a. The Network Load for purposes of assessing the transmission service rate for transmission facilities at 138 kV and above for a Network Customer shall be equal to 100% of the Network Customer's Network Load.
    b. The Network Load for purposes of assessing the transmission service rate for transmission facilities below 138 kV for a Network Customer, other than retail choice providers and providers of last resort ("POLR"), shall be based on metered data adjusted for losses.
    c. For retail choice providers and POLR, the Network Customer's Network Load utilizing transmission facilities below 138 kV shall be the Network Customer's monthly Network Load deemed to be utilizing transmission facilities below 138 kV in each state-approved service territory. A Network Customer's Network Load deemed to be utilizing transmission facilities below 138 kV service in each state-approved service territory shall be the Network Customer's percentage of the Network Load in such service territory multiplied by the total load deemed to be utilizing transmission facilities below 138 kV in such service territory, adjusted for specifically metered load.
    d. The percentage of load in each state-approved service territory that is deemed to be utilizing transmission facilities below 138 kV shall be determined annually pursuant to an ATSI load flow analysis.
    e. For ease in determining the amount of load deemed to be utilizing transmission facilities below 138 kV for each state-approved territory, billing factors for each territory shall be calculated annually, and communicated to customers prior to each rate year (June 1 – May 31).

Billing factors for specifically metered customers shall be communicated confidentially. Billing factors for remaining customers shall be posted to the PJM website. An example calculation of the billing factors is provided in Attachment H-21A, Appendix B.

3. Within the ATSI Zone, a Network Customer's peak load shall be adjusted to include transmission loss percentages for 69 kV and above facilities applied to the measured load, as well as any distribution losses as reflected in applicable state tariffs and/or service agreements that contain specific distribution loss factors for the Network Customer. The transmission loss percentage for load served utilizing 138 kV and above facilities shall be 1.486 percent, and the transmission loss percentage for load served utilizing both 138 kV and above transmission facilities and 69 kV transmission facilities shall be 2.786 percent.

4. The rate and revenue requirement in this attachment shall be effective until amended by ATSI or modified by the Commission.

5. In addition to the rate set forth in paragraphs 1 and 2 above, a Network Customer purchasing Network Integration Transmission Service shall pay for transmission congestion charges, in accordance with the provisions of the Tariff, and any amounts necessary to reimburse ATSI for applicable sales, excise, "Btu," carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

6. Network Customers within the ATSI Zone shall be charged or credited, as appropriate, for recovery of legacy MTEP costs, and for recovery of costs associated with Regional Transmission Expansion Plan ("RTEP") projects under the formula rate provided in Attachment H-21A.

7. Network Customers within the ATSI Zone shall be charged for recovery of costs associated with exit fees from the Midwest ISO, and PJM costs billed to ATSI as part of the migration from the Midwest ISO to PJM under the formula rate provided in Attachment H-21A.

OCC 14

2015-2016 RPM Base Residual Auction Planning Parameters		5/23/2012	680092-v6
See note below on 5-23-12 update.			
	RTO	Notes:	
Installed Reserve Margin (IRM)	15.4%	1. Load data: from 2012 Load Report.	
Pool-Wide Average EFORd	5.90%	2. See "Net CONE" worksheet for Net CONE calculations.	
Forecast Pool Requirement (FPR)	1.0859	3. Fixed Resource Requirement (FRR) load still in 5-year commitment period is included.	
Demand Resource (DR) Factor	0.955	4-6-12 update includes (changes in input data are shown in red):	
Preliminary Forecast Peak Load	163,168.0	Additional FRR load elected by FRR entities on 3-7-12.	
Short-Term Resource Procurement Target	2.5%	Changes in CETO/CETL/Reliability Requirements in LDAs.	
Pre-Clearing BRA Credit Rate, $/MW	**$35,205.17**	Changes in Min Annual Resource and Min Extended Resource Requirements.	

		LOCATIONAL DELIVERABILITY AREA (LDA)							
	RTO	**MAAC**	**EMAAC**	**SWMAAC**	**PS**	**PS NORTH**	**DPL SOUTH**	**PEPCO**	**ATSI**
CETO	NA	100.0	3,860.0	4,720.0	4,600.0	2,240.0	1,510.0	3,380.0	5,280.0
CETL	NA	6,156.0	9,177.0	8,373.0	6,220.0	2,972.0	1,822.0	6,522.0	5,417.8
Reliability Requirement	177,184.1	71,623.0	39,370.0	17,238.0	12,824.0	6,462.0	3,062.0	8,973.0	16,201.0
Total Peak Load of FRR Entities	13,267.1	0	0	0	0	0	0	0	0
Preliminary FRR Obligation	**14,406.7**	0	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR	**162,777.4**	**71,623.0**	**39,370.0**	**17,238.0**	**12,824.0**	**6,462.0**	**3,062.0**	**8,973.0**	**16,201.0**
Short-Term Resource Procurement Target	4,069.4	1,658.9	903.5	384.2	288.4	138.3	65.6	186.0	360.5
Net CONE, $/MW-Day (UCAP Price)	**$320.63**	**$267.61**	**$313.84**	**$267.61**	**$313.84**	**$313.84**	**$313.84**	**$267.61**	**$358.22**
Variable Resource Requirement Curve:									
Point (a) UCAP Price, $/MW-Day	$480.95	$401.42	$470.76	$401.42	$470.76	$470.76	$470.76	$401.42	$537.33
Point (b) UCAP Price, $/MW-Day	$320.63	$267.61	$313.84	$267.61	$313.84	$313.84	$313.84	$267.61	$358.22
Point (c) UCAP Price, $/MW-Day	$64.13	$53.52	$62.77	$53.52	$62.77	$62.77	$62.77	$53.52	$71.64
Point (a) UCAP Level, MW	154,476.4	68,102.2	37,443.0	16,405.7	12,202.2	6,155.7	2,916.8	8,553.7	15,419.3
Point (b) UCAP Level, MW	160,118.5	70,584.8	38,807.6	17,003.2	12,646.7	6,379.7	3,022.9	8,864.7	15,980.8
Point (c) UCAP Level, MW	165,760.7	73,067.4	40,172.3	17,600.7	13,091.2	6,603.7	3,129.0	9,175.7	16,542.4
Participant-Funded ICTRs Awarded	NA	159.0	NA	NA	NA	NA	NA	NA	NA
Post-Clearing BRA Credit Rate (LMT), $/MW	$8,677.13	$10,980.00	$10,980.00	$10,980.00	$10,980.00	$10,980.00	$10,980.00	$10,980.00	$22,298.18
Post-Clearing BRA Credit Rate (ES), $/MW	$9,955.20	$12,258.07	$12,258.07	$12,258.07	$12,258.07	$12,258.07	$12,258.07	$12,258.07	$23,576.26
Post-Clearing BRA Credit Rate (ANL), $/MW	$9,955.20	$12,258.07	$12,258.07	$12,258.07	$12,258.07	$12,258.07	$12,258.07	$12,258.07	$26,132.40
Min Ext Summer Resource Req'ment, MW	155,315.7	61,854.9	28,122.1	7,969.8	5,887.9	3,146.6	1,099.6	2,031.7	10,039.5
Min Annual Resource Req'ment, MW	146,454.9	58,496.3	24,394.6	6,693.1	4,808.2	2,586.6	894.0	1,186.0	9,226.9
FRR Load Requirements:									
Min % Internal Resource Req'ment	NA	98.7%	83.5%	57.7%	57.2%	63.1%	47.2%	32.9%	74.8%
Min % Ext Summer Resource Req'ment	95.0%	86.4%	71.4%	46.2%	45.9%	48.7%	35.9%	22.6%	62.0%
Min % Annual Resource Req'ment	89.1%	81.7%	62.0%	38.8%	37.5%	40.0%	29.2%	13.2%	57.0%

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and Zonal Short-Term Resource Procurement Target.

*** (Asterisk) – LDA has adequate internal resources to meet the reliability criterion.**

DPL and PS Zonal peak loads and Short-Term Resource Procurement Targets include the corresponding DPL SOUTH and PS NORTH values.

LDA/Zone	**CETO**	**CETL (Changes shown in red)**	**CETL to CETO Ratio**	**2011 Zonal W/N Coincident Peak Loads**	**Preliminary Zonal Peak Load Forecast**	**Base Zonal FRR Scaling Factor**	**Short-Term Resource Procurement Target**	**FRR Portion of the Preliminary Peak Load Forecast**	**Preliminary Zonal Peak Load Forecast less FRR load****
RTO	NA	NA	NA	**151,995.0**	**163,168.0**	NA	**4,069.4**	**13,267.1**	**149,900.9**
AE	760.0	> 874.0	> 115%	2,520.0	2,735.0	1.08532	74.2	0.0	2,735.0
AEP	580	> 667.0	> 115%	22,460.0	23,991.0	1.06817	315.6	12,364.7	11,626.3
APS	840.0	> 966.0	> 115%	8,210.0	8,753.0	1.06614	237.6	0.0	8,753.0
ATSI	5,280.0	5,417.8	103%	12,620.0	13,281.0	1.05238	360.5	0.0	13,281.0
BGE	3,630.0	> 4174.5	> 115%	6,960.0	7,298.0	1.04856	198.1	0.0	7,298.0
COMED	1,740.0	> 2001.0	> 115%	21,480.0	23,563.0	1.09697	639.7	0.0	23,563.0
DAYTON	440.0	> 506.0	> 115%	3,180.0	3,498.0	1.10000	95.0	0.0	3,498.0
DEOK	2,840.0	> 3266.0	> 115%	5,250.0	5,665.0	1.07905	129.3	902.4	4,762.6
DLCO	1,370.0	> 1575.5	> 115%	2,800.0	2,969.0	1.06036	80.6	0.0	2,969.0
DOM	*	*	NA	18,530.0	20,341.0	1.09773	552.2	0.0	20,341.0
DPL	1,230.0	> 1414.5	> 115%	3,920.0	4,175.0	1.06505	113.3	0.0	4,175.0
DPL SOUTH	1,510.0	1,822.0	121%	NA	2,417.7	NA	65.6	0.0	2,417.7
JCPL	3,530.0	> 4059.5	> 115%	5,960.0	6,349.0	1.06527	172.4	0.0	6,349.0
METED	1,070.0	> 1230.5	> 115%	2,800.0	3,061.0	1.09321	83.1	0.0	3,061.0
PECO	2,490.0	> 2863.5	> 115%	8,370.0	8,977.0	1.07252	243.7	0.0	8,977.0
PENLC	880.0	> 1012.0	> 115%	2,720.0	3,029.0	1.11360	82.2	0.0	3,029.0
PEPCO	3,380.0	6,522.0	193%	6,600.0	6,853.0	1.03833	186.0	0.0	6,853.0
PL (incl. UGI)	500.0	> 575.0	> 115%	7,065.0	7,584.0	1.07346	205.9	0.0	7,584.0
PS	4,600.0	6,220.0	135%	10,150.0	10,624.0	1.04670	288.4	0.0	10,624.0
PS NORTH	2,240.0	2,972.0	133%	NA	5,094.2	NA	138.3	0.0	5,094.2
RECO	NA	NA	NA	400.0	422.0	1.05500	11.5	0.0	422.0
EMAAC	3,860.0	9,177.0	238%	NA	33,282.0	NA	903.5	0.0	** Used to allocate Short-Term Resource Procurement Target to Zones.
SWMAAC	4,720.0	8,373.0	177%	NA	14,151.0	NA	384.2	0.0	
Western MAAC	*	*	NA	NA	13,674.0	NA	371.2	0.0	
MAAC	100.0	6,156.0	6156%	NA	61,107.0	NA	1,658.9	0.0	
Western PJM	4,440	> 5106.0	> 115%	NA	81,720.0	NA	1,858.3	13,267.1	

Limiting conditions at the CETL for modeled LDAs:

LDA	Limiting Facility
MAAC	Loudoun - Brambleton 500 kV line.
EMAAC	Peach Bottom - Limerick 500 kV line.
SWMAAC	Voltage drop at Brighton 500 kV.
PS	Cedar Grove F - Clifton K 230 kV line.
PSNORTH	Cedar Grove F - Clifton K 230 kV line.
DPLSOUTH	Wye Mill - Long Wood 69 kV line.
PEPCO	Voltage drop at Brighton 500 kV.
ATSI	South Canton 765/345 kV transformer.

4-17-12 Update: SWMAAC and PEPCO CETL values and limiting facility were updated based on corrected rating on Pleasant View - Edwards Ferry 230 kV line.

5-23-12 Update: Added Post-Clearing BRA Credit Rates.

RPM CONE and E&AS Values for 2015/2016 Base Residual Auction

ICAP to UCAP Conversion Factor:	
UCAP Price = ICAP Price/(1 - Pool-Wide Average EFORd)	
Pool-Wide Average EFORd for 2015/2016 =	**5.90%**

CONE Area 1: AE, DPL, JCPL, PECO, PS, RECO
CONE Area 2: BGE, PEPCO
CONE Area 3: AEP, APS, ATSI, ComEd, Dayton, DEOK, Duquesne (DLCo)
CONE Area 4: MetEd, Penelec, PPL
CONE Area 5: Dominion
MAAC CONE used is the lowest of the three CONE Areas 1, 2, and 4.
RTO CONE is the 2012/2013 value specified in the OATT escalated.

	CONE Area 1	**CONE Area 2**	**CONE Area 3**	**CONE Area 4**	**CONE Area 5**	**MAAC: Used Area 2 CONE**	**RTO**
Benchmark CONE (2014/2015 BRA Value): Levelized Revenue Requirement, \$/MW-Year	\$138,646	\$128,226	\$131,681	\$128,226	\$128,340	\$128,226	\$128,226
12 Months Handy Whitman Index (July 1, 2011)	2.4%	2.4%	2.0%	2.4%	2.4%	2.4%	2.4%
Region basis for the Handy Whitman Index	North Atlantic	North Atlantic	North Central	North Atlantic	South Atlantic	North Atlantic	North Atlantic
2015/2016 BRA CONE, escalated by Handy Whitman Index, \$/MW-Year	\$141,973	\$131,303	\$134,314	\$131,303	\$131,420	\$131,303	\$131,303
Historic (2009-2011) Net Energy Revenue Offset, \$/MW-Year for the Zone in the CONE Area Specified	\$31,686	\$36,937	\$8,741	\$27,734	\$30,173	\$36,937	\$18,678
Zonal LMP used for Net Energy Offset Calculation	AE Zonal LMP	BGE Zonal LMP	ComEd Zonal LMP	MetEd Zonal LMP	Dominion Zonal LMP	BGE Zonal LMP	PJM Average LMP
Ancillary Services Offset, \$/MW-Year per Tariff	\$2,199	\$2,199	\$2,199	\$2,199	\$2,199	\$2,199	\$2,199
Net CONE, \$/MW-Day, ICAP Price	\$295.32	\$251.82	\$337.09	\$276.97	\$270.62	\$251.82	\$301.71
Net CONE, \$/MW-Day, UCAP Price	**\$313.84**	**\$267.61**	**\$358.22**	**\$294.33**	**\$287.59**	**\$267.61**	**\$320.63**

New Key Transmission Upgrades included for 2015/2016 model		
Upgrade ID	Description	Transmission Owner
b0487	Construct a Susquehanna - Roseland 500kV circuit (PPL 500 kV equipment)	PPL
b0879	Build a new Wye Mills-Church 138 kV line	DPL
b1197	Reconductor the PECO portion of the Burlington - Croydon circuit	PECO
b1197.1	Reconductor the PSEG portion of the Burlington - Croydon circuit with 1590 ACSS	PSEG
b1224	Install 2nd Clover 500/230 kV transformer and a 150 MVAr capacitor	Dominion
b1251	Rebuild the existing Bagley - Raphael Rd. 230 kV line to double circuit 230 kV line	BGE
b1251.1	Reconfigure Raphael Rd. to terminate new circuit	BGE
b1281	Build new Hayes 345/138 kV substation with new 138 kV lines to: Greenfield #1, Greenfield #2, and Avery.	ATSI
b1282	Build Beaver - Hayes - Davis - Besse #2 345 kV line	ATSI
b1283	Loop the Chamberlin - Mansfield 345 kV line into the Hanna 345 kV substation	ATSI
b1300	Reconductor the East Frankfort - Goodings Grove 345 kV 11601 line	ComEd
b1304.1	Convert the existing 'D1304' and 'G1307' 138 kV circuits between Roseland - Kearny- Hudson to 230 kV operation	PSEG
b1304.2	Expand existing Bergen 230 kV substation and reconfigure the Athenia 230 kV substation to breaker and a half scheme	PSEG
b1304.3	Build second 230 kV underground cable from Bergen to Athenia	PSEG
b1304.4	Build second 230 kV underground cable from Hudson to South Waterfront	PSEG
b1321	Build a new 230 kV line North Anna - Oak Green and install a 224 MVA 230/115 kV transformer at Oak Green	Dominion
b1325	Rebuild 15 miles of line #2020 Winfall - Elizabeth City with a minimum 900 MVA rating	Dominion
b1328	Uprate the 3.63 mile line section between Possum and Dumfries substations, replace the 1600 amp wave trap at Possum Point	Dominion
b1331	Build a 230 kV line from Shawboro to Aydlett tap and connect Aydlett to the new line	Dominion
b1383	Install 2nd 500/138 kV transformer at 502 Junction	APS
b1398	Build two new parallel underground circuits from Gloucester to Camden (via Cuthbert Blvd)	PSEG
b1398.3	Build a second 230 kV parallel overhead circuit from Mickleton – Gloucester	PSEG
b1398.4	Reconductor the existing Mickleton – Gloucester 230 kV circuit (PSEG portion)	PSEG
b1398.5	Reconductor the existing Mickleton – Gloucester 230 kV circuit (AE portion)	AEC
b1398.8	Reconductor Richmond – Waneeta 230 kV and replace terminal equipments at Waneeta substation	PECO
b1465.1	Add a 3rd 2250 MVA 765/345 kV transformer at Sullivan station and 345 kV switching changes at Sullivan/Breed	AEP
b1495	Add an Additional 765/345 kV transformer at Baker Station. Replace Baker 345 kV breakers 'G', 'G2', 'J1', 'G1, 'J', and 'J2'.	AEP
b1507.1	Mt Storm - Doubs 500 kV transmission line rebuild in both West Virginia and Virginia	Dominion
b1507.2	Terminal Equipment upgrade at Doubs substation	APS
b1507.3	Mt Storm - Doubs transmission line rebuild in Maryland	APS
b1508.1	Build a 2nd 230kV Line Harrisonburg to Endless Caverns	Dominion
b1590	Upgrade the PSEG portion of the Camden - Richmond 230 kV circuit to six wire conductor and replace terminal equipments at Camden	PSEG
b1590.1	Upgrade the PECO portion of the Camden - Richmond 230 kV to a six wire conductor	PECO
b1659	Establish Sorenson 345/138 kV station as a 765/345 kV station	AEP
b1663	Install a new 765/138 kV transformer at Jackson Ferry substation	AEP
b1797	Wreck and rebuild 7 miles of the Dominion owned section of Cloverdale - Lexington 500 kV	Dominion
b1798	Build a 450 MVAR SVC and 300 MVAR switched shunt at Loudoun 500 kV	Dominion
b1799	Build 150 MVAR Switched Shunt at Pleasant View 500 kV	Dominion
b1801	Build a 250 MVAR SVC at Altoona 230 kV	ME
b1803	Build a 300 MVAR Switched Shunt at Doubs 500 kV and increase (~50 MVAR) in size the existing Switched Shunt at Doubs 500 kV	APS

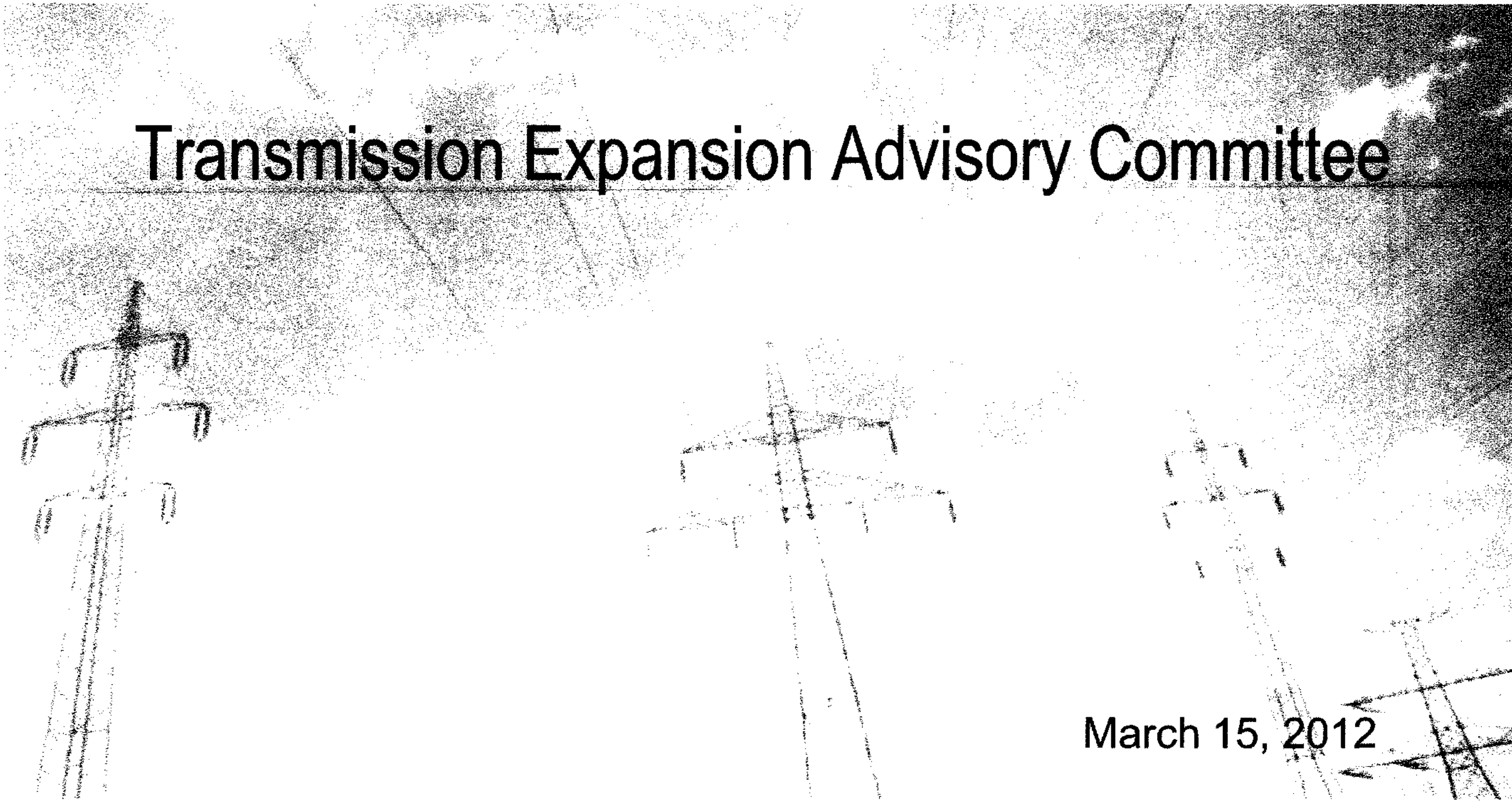
New Key Transmission Upgrades added since Posting Planning Parameters on February 1, 2012		
	Install a 2nd 345/138 kV transformer at the Allen Junction station.	ATSI
	Loop the Homer City-Handsome Lake 345 kV line into the Armstrong substation and install a 345/138 kV transformer at Armstrong.	APS
	Install a 138/69 kV transformer at the Avery station	ATSI
	Upgrade terminal equipment on the Avon – Crestwood 138 kV line.	ATSI
b1837	Replace breaker risers at Marlowe 138 kV and wave traps at Marlowe 138 kV and Bedington 138 kV	APS
	Install a 2nd 345/138 kV transformer at the Bayshore station	ATSI
	Create a new Harmon 345/138/69 kV substation by looping in the Star – South Canton 345 kV line	ATSI
	Build a new Harmon – Brookside/Longview 138 kV line.	ATSI
	Install a 345/138 kV transformer at the Inland Q-11 station	ATSI
	Install a 138 kV circuit breaker at the Inland Q-11 station	ATSI
	Install a 100 MVAR capacitor bank at the Maclean 138 kV station.	ATSI
	Create a new Northfield 345 kV switching station by looping in the Eastlake – Juniper 345 kV line and the Perry - Inland 345 kV line.	ATSI
	Re-conductor the Galion – GM Mansfield 138 kV line with 477 ACSS	ATSI
	Re-conductor the Galion – Leaside 138 kV line with 336 ACSS.	ATSI
	Rebuild the South canton –Harmon 345kV line.	ATSI/AEP
b1609	Construct Four Mile 230/115 kV substation	PN
s0365	At the Star 345 kV substation, add 2 150 MVar cap banks (300 MVAR total)	ATSI
s0366	Hanna 345 kV substation - add 2 150 MVar cap banks (300 MVAR total)	ATSI
s0368	Install 50 MVar permanent cap bank at Clark 138 kV station	ATSI
	Burlington - Croydon 230 kV upgrade	PECO/PSEG
b1588	Reconductor the Eagle Point - Gloucester 230 kV circuit # 1 and #2 with higher conductor rating	PSEG

Key Transmission Upgrades included for 2014/2015 model but not included for 2015/2016 model		
b0284.1	Build Jack's Mountain 500kV substation - Tap the Keystone - Juniata and Conemaugh - Juniata 500kV, connect the circuits with a breaker and half scheme, and install new 400 MVAR capacitor	PENELEC
b0369	Install 100 MVAR Fast Switched Capacitor Banks at Jack's Mountain 500kV substation	PENELEC
b0370	Install 500 MVAR Fast Switched Capacitor Banks at Jack's Mountain 500kV substation	PENELEC
b0877	Build a 2nd Vienna-Steele 230 kV line	DPL

2015/2016 Minimum Resource Requirements									
Forecast Pool Requirement	1.0859								
Demand Resource Factor	0.955								
Quantities are in Unforced Capacity Megawatts	**PJM Region**	**MAAC**	**EMAAC**	**SWMAAC**	**PS**	**PS NORTH**	**DPL SOUTH**	**PEPCO**	**ATSI**
Reliability Requirement adjusted for FRR	162,777.4	71,623.0	39,370.0	17,238.0	12,824.0	6,462.0	3,062.0	8,973.0	16,201.0
CETL	NA	6,156.0	9,177.0	8,373.0	6,220.0	2,972.0	1,822.0	6,522.0	5,417.8
Preliminary Peak Load Forecast	163,168.0	61,107.0	33,282.0	14,151.0	10,624.0	5,094.2	2,417.7	6,853.0	13,281.0
FRR Peak Load	13,267.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Peak Load Forecast adjusted for FRR	149,900.9	61,107.0	33,282.0	14,151.0	10,624.0	5,094.2	2,417.7	6,853.0	13,281.0
Limited Demand Resource Reliability Target									
Percent of Preliminary Forecast Peak Load	**4.8%**	**5.7%**	**6.0%**	**6.1%**	**6.5%**	**6.5%**	**5.6%**	**5.9%**	**5.4%**
Unforced Capacity, MW	7,461.7	3,612.1	2,070.9	895.2	716.1	343.4	140.4	419.3	743.7
Extended Summer Demand Resource Reliability Target									
Percent of Preliminary Forecast Peak Load	**10.5%**	**11.0%**	**16.8%**	**14.8%**	**16.3%**	**17.1%**	**13.8%**	**17.8%**	**11.3%**
Unforced Capacity, MW	16,322.5	6,970.7	5,798.4	2,171.9	1,795.8	903.4	346.0	1,265.0	1,556.3
Minimum Resource Requirements for RPM, MW									
Minimum Extended Summer Resource Requirement	**155,315.7**	**61,854.9**	**28,122.1**	**7,969.8**	**5,887.9**	**3,146.6**	**1,099.6**	**2,031.7**	**10,039.5**
Minimum Annual Resource Requirement	**146,454.9**	**58,496.3**	**24,394.6**	**6,693.1**	**4,808.2**	**2,586.6**	**894.0**	**1,186.0**	**9,226.9**
Minimum Resource Requirements for FRR (% Obligation)									
Minimum Extended Summer Resource Requirement	**95.0%**	**86.4%**	**71.4%**	**46.2%**	**45.9%**	**48.7%**	**35.9%**	**22.6%**	**62.0%**
Minimum Annual Resource Requirement	**89.1%**	**81.7%**	**62.0%**	**38.8%**	**37.5%**	**40.0%**	**29.2%**	**13.2%**	**57.0%**

OCC 15

Transmission Expansion Advisory Committee



March 15, 2012

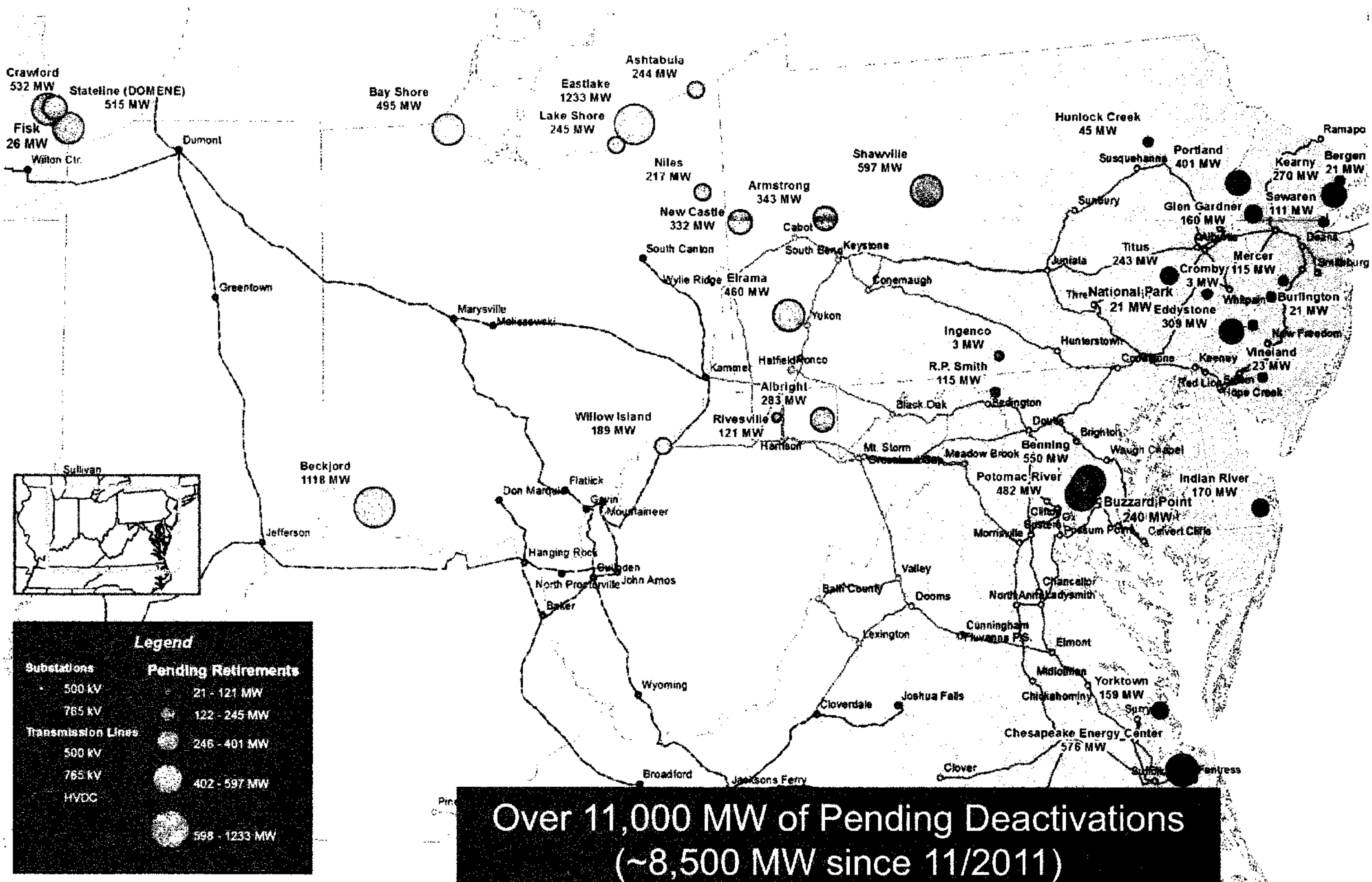
Issues Tracking

Issues Tracking

- Open Issues
  - None
- New Issues

Generation Retirements

All Pending Generator Deactivations



Over 11,000 MW of Pending Deactivations
(~8,500 MW since 11/2011)

Deactivations received since 11/1/2011

Units	Trans Zone	Requested Deactivation Date	Status
Walter C Beckjord 1, 2, & 3	DEOK	5/1/2012	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by May 1, 2012
Niles 1 & 2	ATSI	6/1/2012	Reliability Analysis Underway
Elrama ~~1,~~ 2, 3, & 4	DUQ	6/1/2012	Reliability Analysis Underway
Armstrong 1, & 2; Ashtabula 5; Bay Shore 2, 3, & 4; Eastlake 1, 2, 3, 4, & 5; Lake Shore 18; R Paul Smith 3 & 4	ATSI	9/1/2012	Reliability analysis complete. Impacts identified and expected to be resolved by June 2016. Further refinement of the reliability analysis, required upgrades, and generator deactivation schedule continues.
Albright 1, 2, & 3; Rivesville 5 & 6; Willow Island 1 & 2	APS	9/1/2012	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by May 2013
Chesapeake 1 & 2; Yorktown 1	DOM	12/31/2014	Reliability Analysis complete. Impacts identified. Potential upgrades under review
Portland 1 & 2	MetEd	1/7/2015	Reliability Analysis Underway
New Castle 3, 4, & 5; New Castle Diesels A & B	ATSI	4/16/2015	Reliability Analysis Underway
Titus 1, 2, 3	MetEd	4/16/2015	Reliability Analysis Underway
Shawville 1, 2, 3, & 4	PenElec	4/16/2015	Reliability Analysis Underway
Walter C Beckjord 4, 5, & 6	DEOK	5/1/2015	Reliability Analysis complete - impacts identified - upgrades scheduled to be completed by June 2014

Deactivations received since 11/1/2011

Units	Trans Zone	Requested Deactivation Date	Status
Glen Gardner CT 1, 2, 3, 4, 5, 6, 7, & 8	JCPL	5/1/2015	Reliability Analysis Underway
Bergen 3; Burlington 8; National Park 1; Mercer 3; Seawaren 6	PSEG	6/1/2015	Reliability Analysis Complete. Impacts identified and expected to be resolved in three - four years. Working with affected TO to finalize upgrade schedule.
Chesapeake 3 & 4	DOM	12/31/2015	Reliability Analysis complete. Impacts identified. Potential upgrades under review

PSEG (PSEG Energy) Deactivations – Deactivations

Bergen 3; Burlington 8; National Park 1; Mercer 3; Seawaren 6

Requested deactivation date: 6/1/2015

- Initial analysis identified potential issues
  - Advance b1588 to 2015 or if not feasible then Operating procedure or SPS in the interim
  - Replace short section of Croydon-Burlington line inside Croydon substation – Estimated IS date 6/1/2015

DOM (Dominion Resources) Deactivations

Chesapeake 1 & 2; Yorktown 1

Requested deactivation date: 12/31/2014

Chesapeake 3 & 4

Requested deactivation date: 12/31/2015

- Initial analysis identified potential issues
  - Proposals for solutions received from LS Power and Dominion

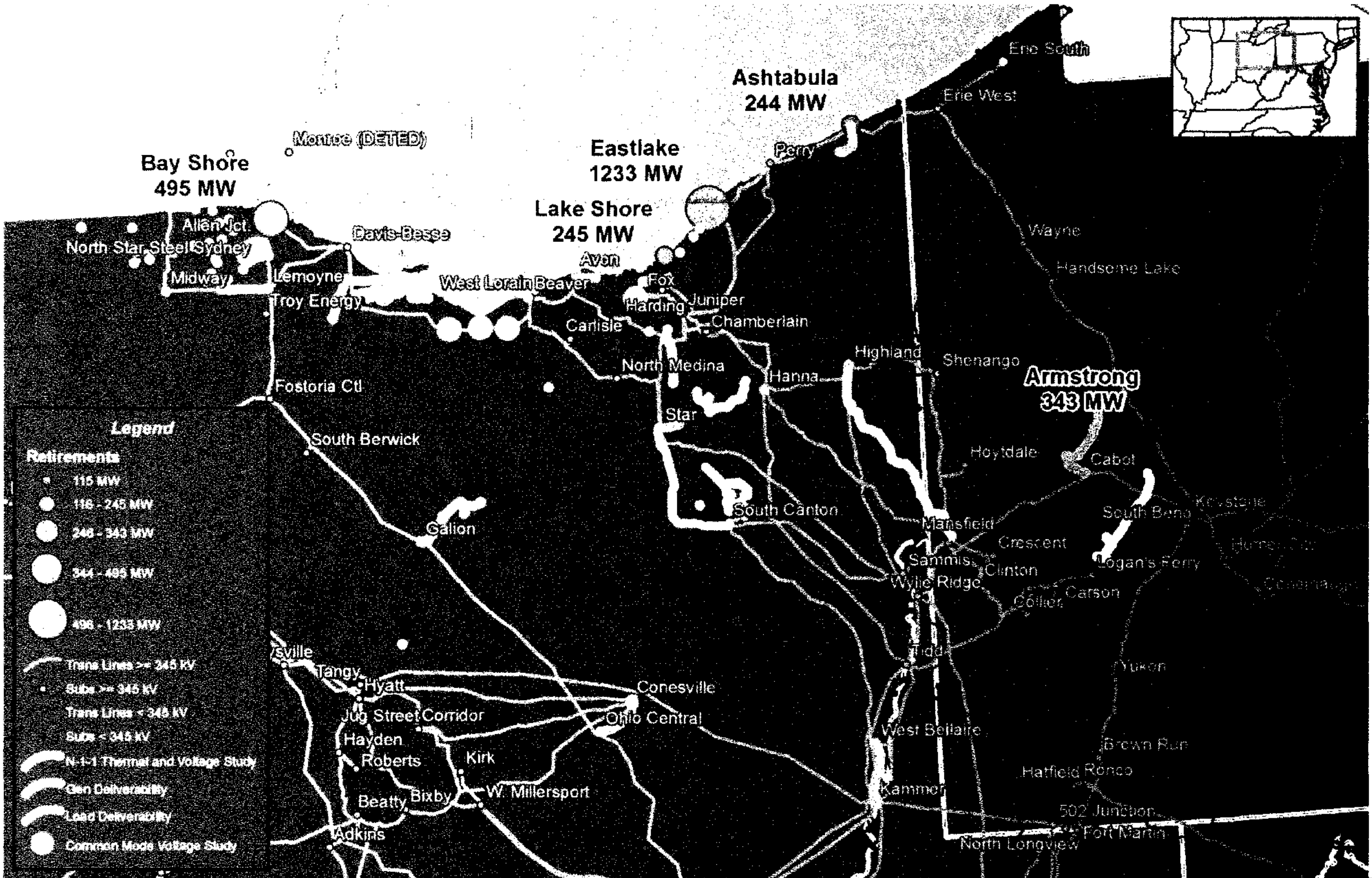
ATSI (FES) Deactivations – Status and Next Steps

Armstrong 1, & 2; Ashtabula 5; Bay Shore 2, 3, & 4;
Eastlake 1, 2, 3, 4, & 5; Lake Shore 18;
R Paul Smith 3 & 4

Requested deactivation date: 9/1/2012

- Initial analysis identified potential issues (see posted material) for summer 2013
- Analysis of future years is in-progress
- Next steps will identify the solutions and the timing of the solutions including the need to retain some of the generation on RMR

ATSI / APS (FES) Deactivations – Initial Results



DEOK (Duke Energy) Deactivations

<u>Beckjord 1, 2, & 3</u>

Requested deactivation date: 5/1/2012

- Analysis completed with upgrades needed to uprate breakers and disconnect switches at Silver Grove as well as installing temporary cooling for Silver Grove 345/138kV transformer– Estimated IS date is 5/1/2012

<u>Beckjord 4, 5, & 6</u>

Requested deactivation date: 5/1/2015

- Upgrade currently underway to reconfigure Red Bank bus to ring bus configuration – Estimated IS date 6/1/2013

FES (APS) Deactivations

Albright 1, 2, & 3; Rivesville 5 & 6; Willow Island 1 & 2

Requested deactivation date: 9/1/2012

- Existing Project b1142 - Reconductor the Bartonville – Stephenson 138 kV; Stonewall - Stephenson138 kV line
  - IS Date can be advanced to 6/1/2013
- Voltage issues may be resolved through either a revision to the Belmont SPS or installation of capacitors at Belmont 138kV

2012 RTEP
Scenario and Sensitivity Analyses

2012 RTEP - Renewable Portfolio Standards Scenarios

Renewable Portfolio Standards

- Overall Assumptions
  - Model the latest Renewable Portfolio Standards (RPS) state targets
    - Assume production from renewable wind
    - Update target PJM installed renewable MW requirements
    - Update installed reserve calculation
  - 2012 PJM Load Forecast Report
    - 15 Year Load Forecast
    - Include Demand Response (DR) and Energy Efficiency (EE)
  - Incorporate findings from 2011 RTEP RPS scenario studies

RPS – Scenario #1

- Assumptions
  - Assume RPS supply from PJM resources
  - **7 GW Offshore**
  - Study year: 2027
- Analysis
  - Reliability Analysis
    - Generator Deliverability (50/50 load level)
    - Common Mode Outage test (50/50 load level)
  - Market Efficiency Analysis
    - Security Constrained Optimal Power Flow (SCOPF)
    - Production cost simulation using PROMOD
- Result
  - Thermally overloaded facilities
  - Congestion $"s
  - Develop transmission overlay

RPS – Scenario #2

- Assumptions
  - **0 GW Offshore**
  - Otherwise, same as RPS – Scenario #1 but with a 0 GW offshore assumption
  - The remainder of the state target RPS will be sourced from inland PJM resources

RPS – Scenario #3

- Assumptions
  - **RPS Source from Neighboring Entities**
  - Otherwise, same as RPS – Scenario #2 (assume 0 offshore)
  - The remainder of the state target RPS will be sourced from inland PJM resources
- Neighboring Entities
  - Assume 40% of the PJM RPS supplied from renewable wind in the Midwest ISO (MISO)
    - Assume DC injection points from MISO to PJM
    - Injection points to PJM to be determined

2012 RTEP - High Load Growth Scenario

High Load Growth

- Overall Assumptions
  - 2012 PJM Load Forecast Report
    - 15 Year Load Forecast
    - Include Demand Response (DR) and Energy Efficiency (EE)
  - PJM Load Forecast based on Moody"s High Economic Growth Forecast
  - 2017 RTEP Base Case
- Analysis
  - Reliability Analysis
    - 15 Year Analysis
- Result
  - Thermally overloaded facilities with and without the high load growth forecast that demonstrate the relative impact of the alternate forecast

2012 RTEP - At Risk Generation Scenarios

At-Risk Generation

- Purpose
  - Identify potential regional and local reliability concerns
- Overall Assumptions
  - 2016 RTEP Base Case
  - 2012 PJM Load Forecast Report
    - Include Demand Response (DR) and Energy Efficiency (EE)
- At-risk generation
  - Announced retirements
  - Coal Plant Size and Age
  - State agency feedback
  - Media publication
  - Other at-risk

At-Risk Generation – Scenario #1

- Assumptions
  - **Same as 2012 RTEP base except "at-risk" generation'**
- Analysis
  - Reliability Analysis
    - Generator Deliverability (50/50 load level)
    - Common Mode Outage test (50/50 load level)
    - N-1-1 outage test (50/50 load level)
    - Load Deliverability (90/10 load level)
- Result
  - Thermal overloads & voltage violations

2012 RTEP Scenario Analysis – Status & Next Steps

- Data
- Assumptions
- Analysis
- Results

2012 PJM Baseline Reliability

ARR Analysis

Preliminary Stage 1A 10-Year ARR analysis

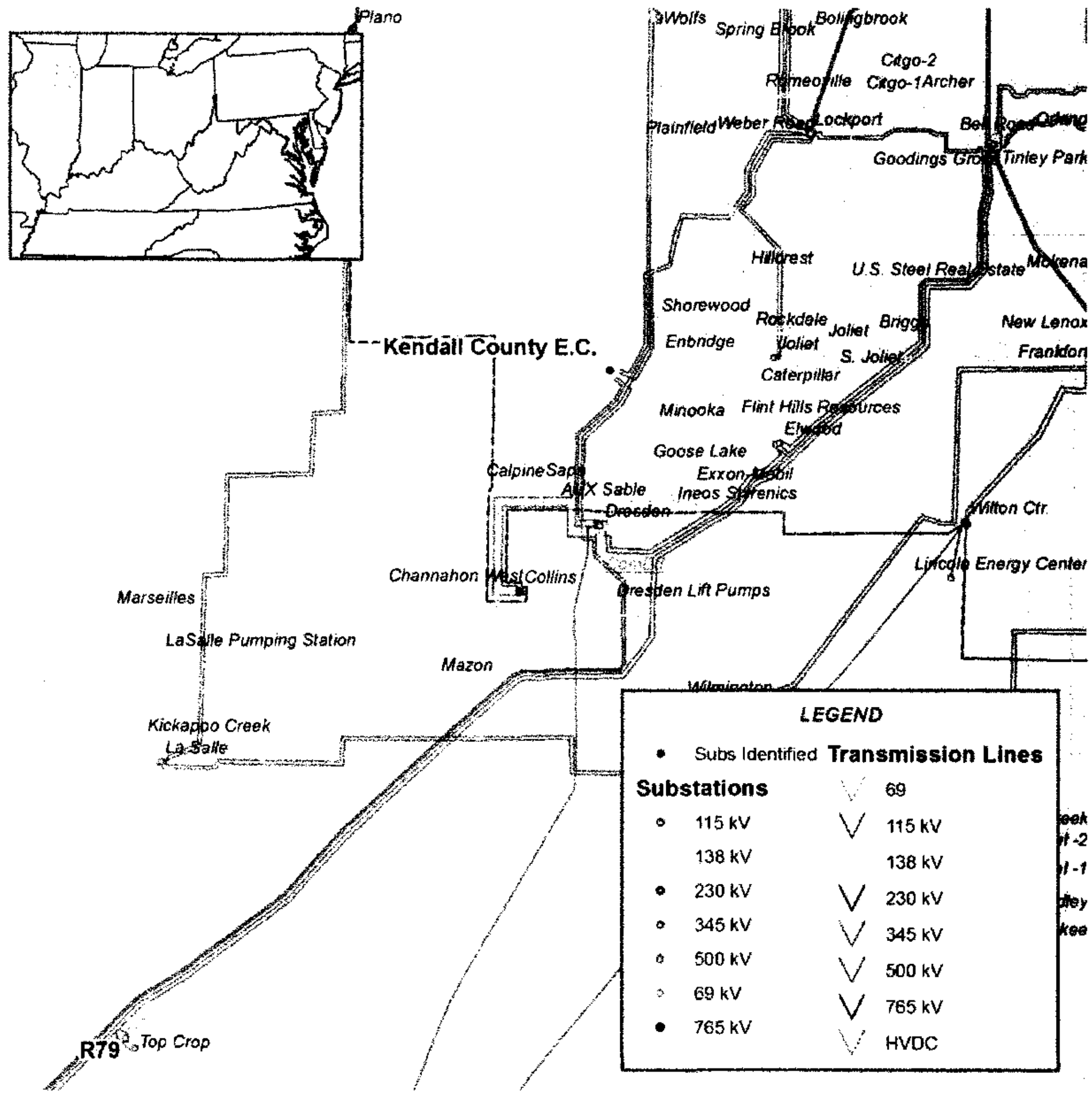
- Section 7.5 (b) of Schedule 1 of OA indicates:
  - On an annual basis PJM shall conduct a simultaneous feasibility analysis test for stage 1A ARRs which shall access the simultaneous feasibility for each year remaining in terms of the rights. This test shall be based on the ARRs required to meet zonal base load requirements. PJM shall apply a zonal load growth rate for the 10 year term of stage 1A ARRs.
- The preliminary 10-year analysis on 2012/13 Stage 1A ARRs resulted in infeasibility on the following facilities. Upgrades will need to be developed to address the infeasibilities

Monitored Element	Contingency Description	Type
122 Belvidere - 12205 Line 138 KV 12205 1	345L15616 Cherry Valley-Silver Lake 345 kV Line	Internal
138 Silver Lake - 156 Cherry Valley 345 KV 15616	345L15502 Nelson-Electric Jct 345 kV Line	Internal
Belmont 500 KV Tran 3	BELMONT 500/138 #1 & #2 (APS)	Internal
Breed - Wheatland 345 KV BRE-WHE1	JEFFERSON ROCKPORT 765KV LINE	M2M Flowgate
Kenosha - Lakeview 138 KV 9341	Zion-Pleas PR (2221) 345 Line	M2M Flowgate
Oak Grove - Galesburg 161 KV OAK-GAL	345L15502 Nelson-Electric Jct 345 kV Line	M2M Flowgate
Pleasant Prairie - Zion 345 KV 2221	Cherry Valley-Silver Lake 345kV (15616 line)	M2M Flowgate
Lakeview - Zion 138 KV	Zion-Pleas PR (2221) 345 Line	M2M Flowgate

Note: *Final* 10 -Year ARR analysis may identify *additional* facilities

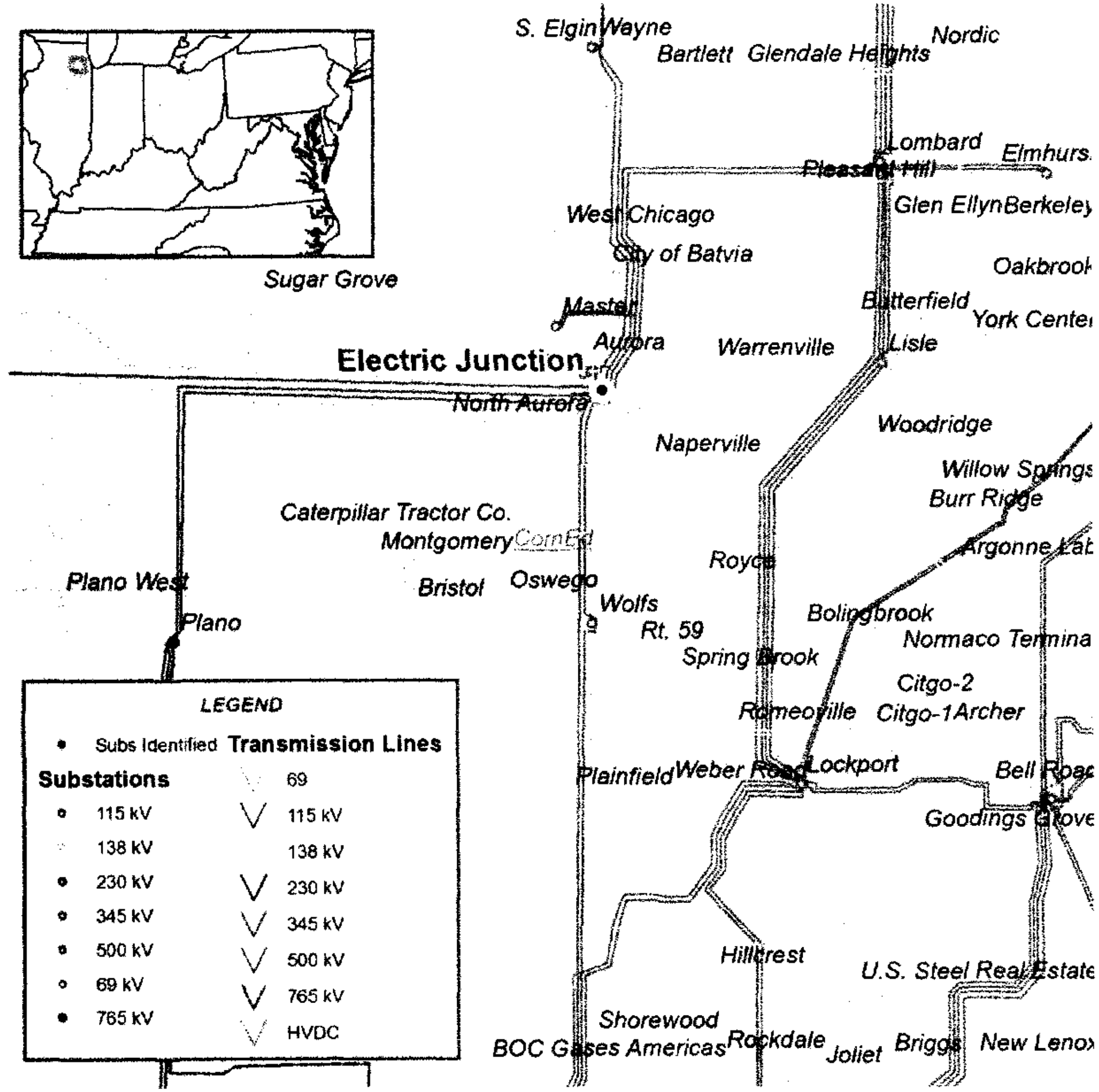
ComEd Transmission Zone

- Light Load Voltage Violation
- High voltage at Kendall and R79 Tap 345kV buses for the loss of Kendall County – Lockport 345kV line (#10805)
- Install a 345 kV normally closed bus tie CB at Kendall County (B1886)
- Estimated Project Cost: $2.8M
- Expected IS date: 03/01/2014



ComEd Transmission Zone

- N-1-1 Thermal Violation
- The Electric Junction 345/138/34.5kV transformer #83 is overloaded for the loss of the Electric Junction – W407K –W407M – Lombard Red 345KV line (#11120) and the loss of W407K – Aurora "Red" 345 kV line (14419)
- Upgrade five 345 kV circuit breakers (L1223, L11124, L14321, BT2-3 and BT3-4) at Electric Junction (B1852.1)
- Modify reclosing on 138kV line (L11103) at TSS 111 Electric Junction (B1852.2)
- Estimated Project Cost: $2.5M
- Expected IS date: 06/01/2016



ComEd Transmission Zone

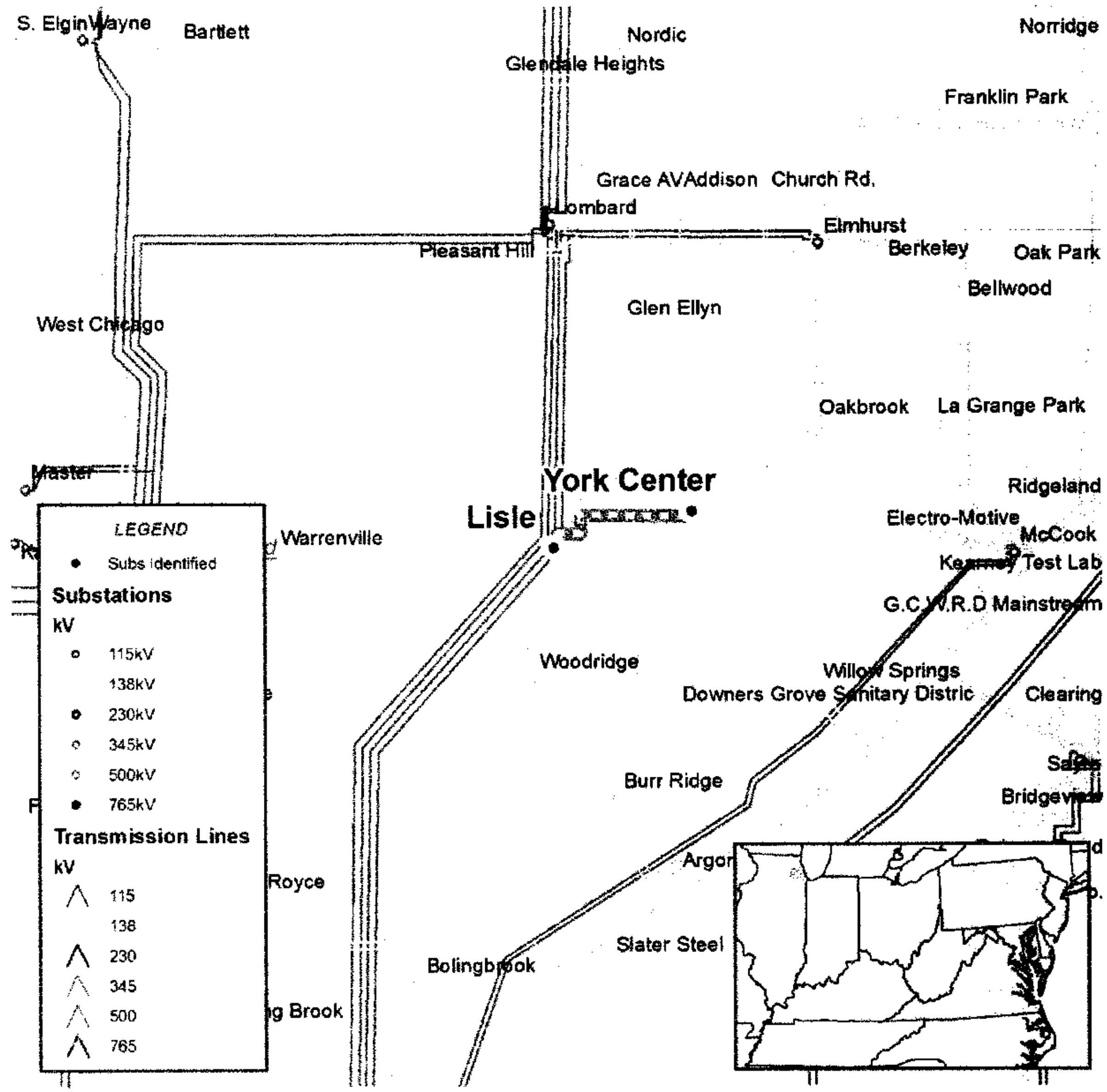
- Cancel Baseline Project

- Cancel B1266: Normally close 345 kV BT 2-3 at TSS 103 Lisle, replace one 345 kV circuit breaker on BT 1-2 at TSS 103 Lisle

- Advance the Expected IS date of B1844 and B1845 to 06/01/2015

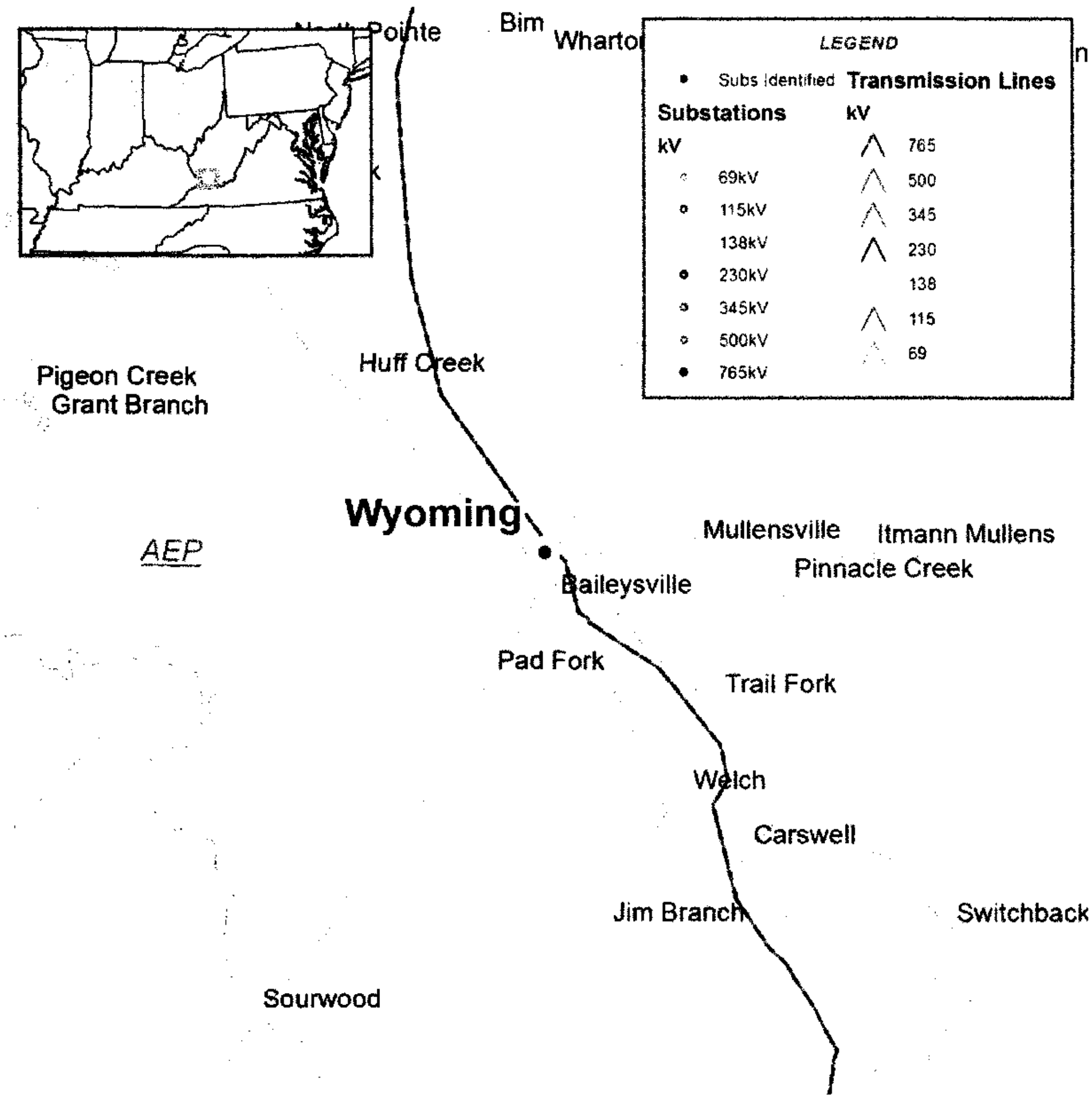
✓ Reconductor 2.4 miles of 138 kV line 10302 from TSS 103 Lisle to York Tap with ACSS(B1845)

✓ Reconductor 2.1 miles of 138 kV line 10301 from TSS 103 Lisle to York Tap with ACSS(B1844)



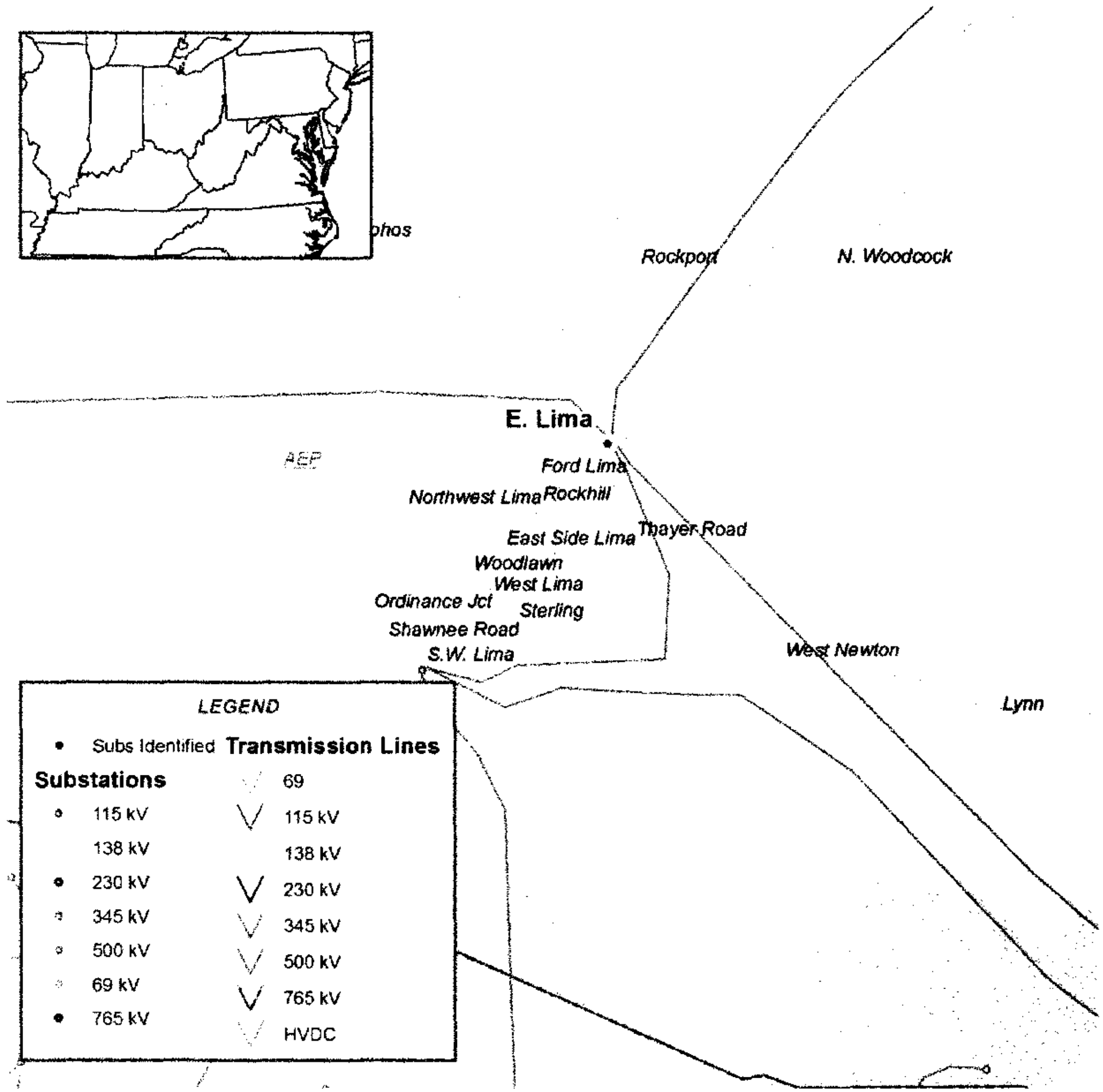
AEP Transmission Zone

- Project Cost Change for B1661: Install a 765 kV circuit breaker at Wyoming station
- Old Cost estimate: $2M
- New Cost estimate: $5M
- Expected IS date: 6/1/2015



AEP Transmission Zone

- Common Mode Violation
- The East Lima 345/138KV transformer #2 is overloaded for the loss of the East Lima – Fostoria Central 345kV line with stuck break at East Lima 345KV
- Switch the breaker position of transformer #1 and SW Lima at East Lima 345kV bus (B1883)
- Estimated Project Cost: $1.0M
- Expected IS date: 06/01/2016

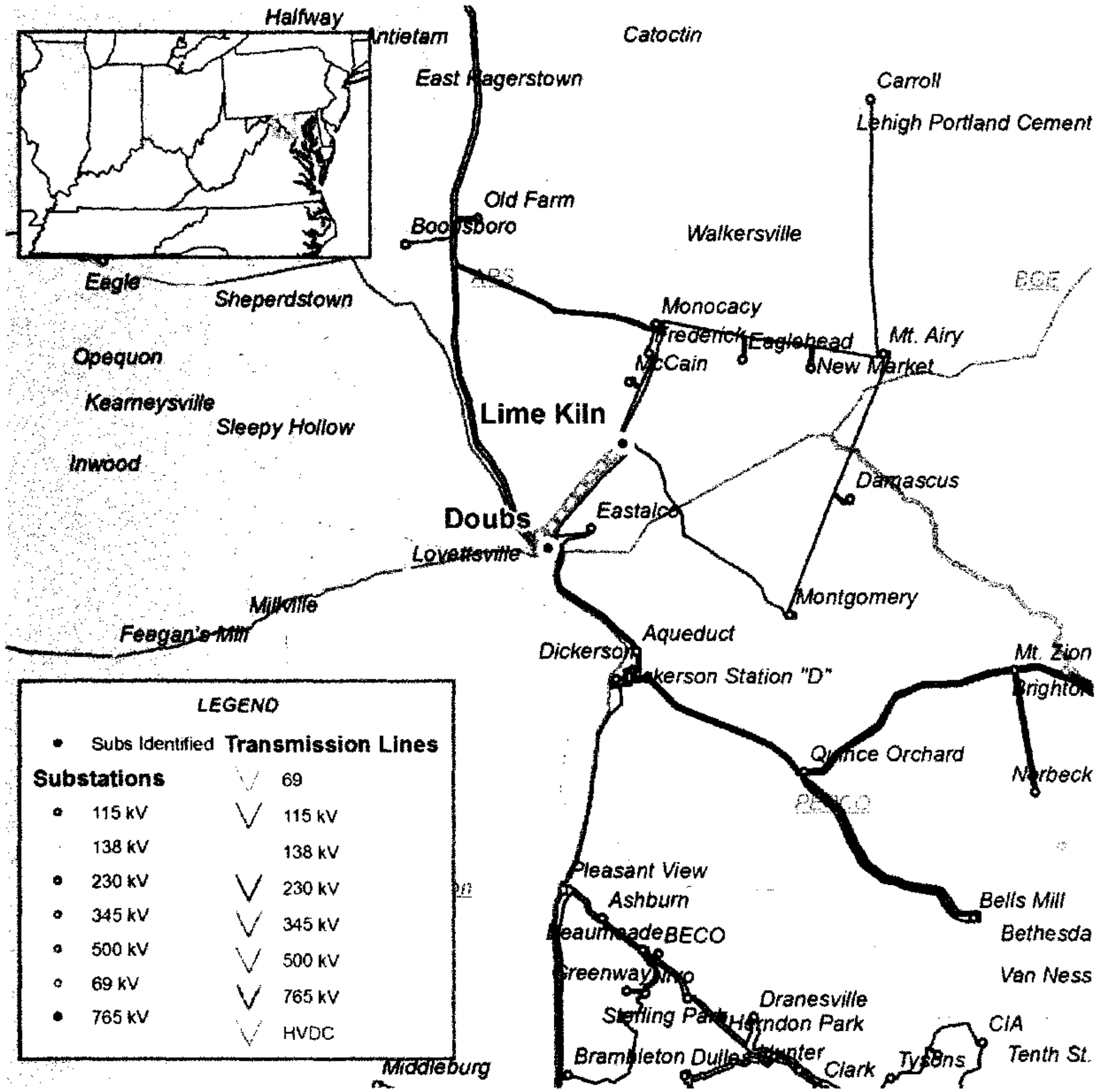


APS Transmission Zone

- Project Replacement

- Cancel Project b0676.2:
  - ✓ Reconductor Doubs - Lime Kiln (#231) 230kV
  - ✓ Estimated Project Cost: $3.1M
  - ✓ Expected IS Date: 06/01/2013

- Replaced by B1833:
  - ✓ Replace the 1200 A line side and bus side disconnect switches with 1600 A switches, replace bus side, line side, and disconnect leads at Lime Kiln SS on the Doubs-Lime Kiln 2 (231) 230 kV line terminal.
  - ✓ Estimated Project Cost: $0.12M
  - ✓ Expected IS date: 06/01/2016



APS Transmission Zone

- Project Replacement

- Cancel Project b0676.1:

✓ Reconductor Doubs - Lime Kiln (#207) 230kV

✓ Estimated Project Cost: $3.5M

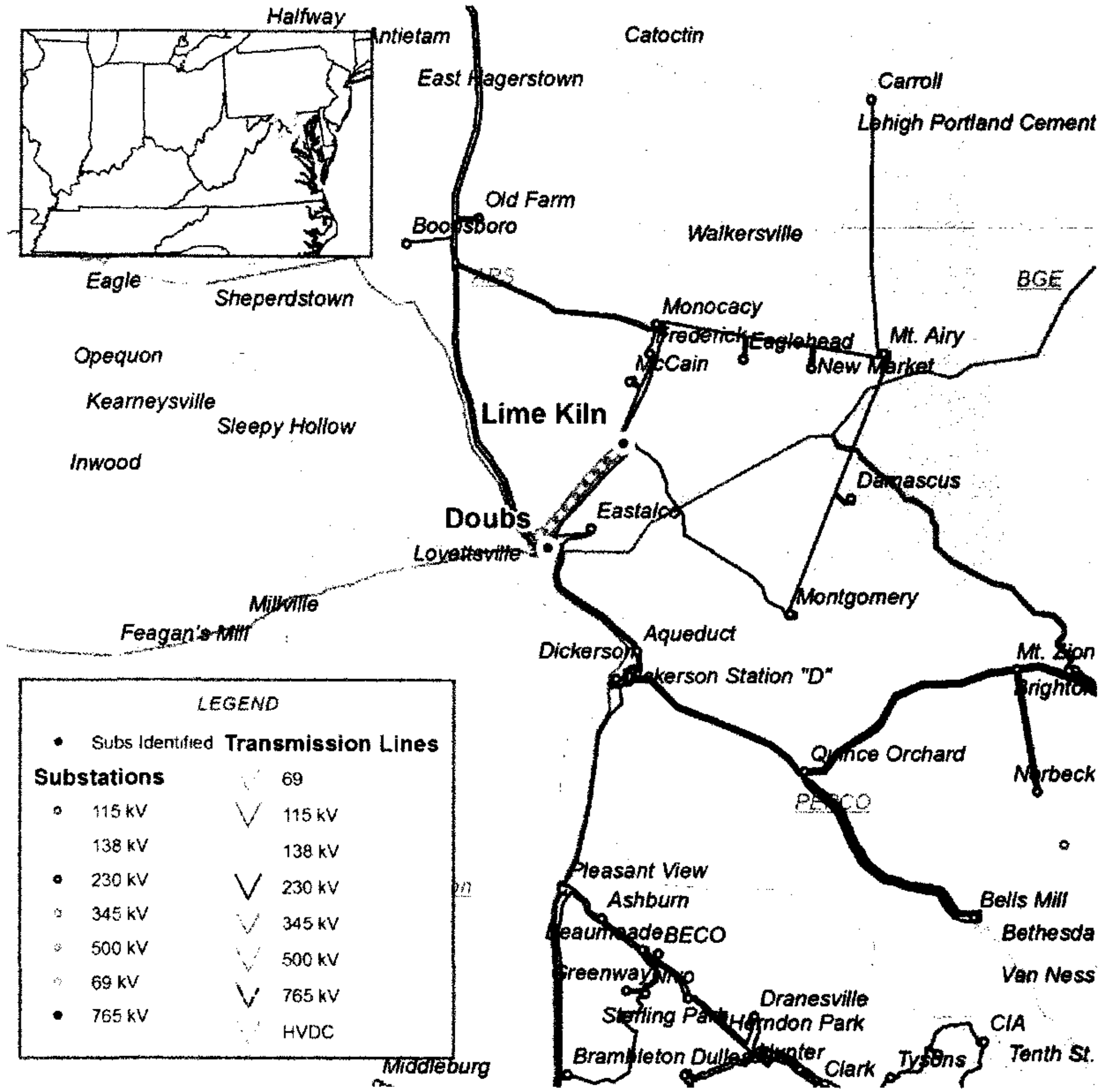
✓ Expected IS Date: 06/01/2013

- Replaced by B1832:

✓ Replace the 1200 A line side and bus side disconnect switches with 1600 A switches, replace bus side, line side, and disconnect leads at Lime Kiln SS on the Doubs-Lime Kiln 1 (207) 230 kV line terminal..

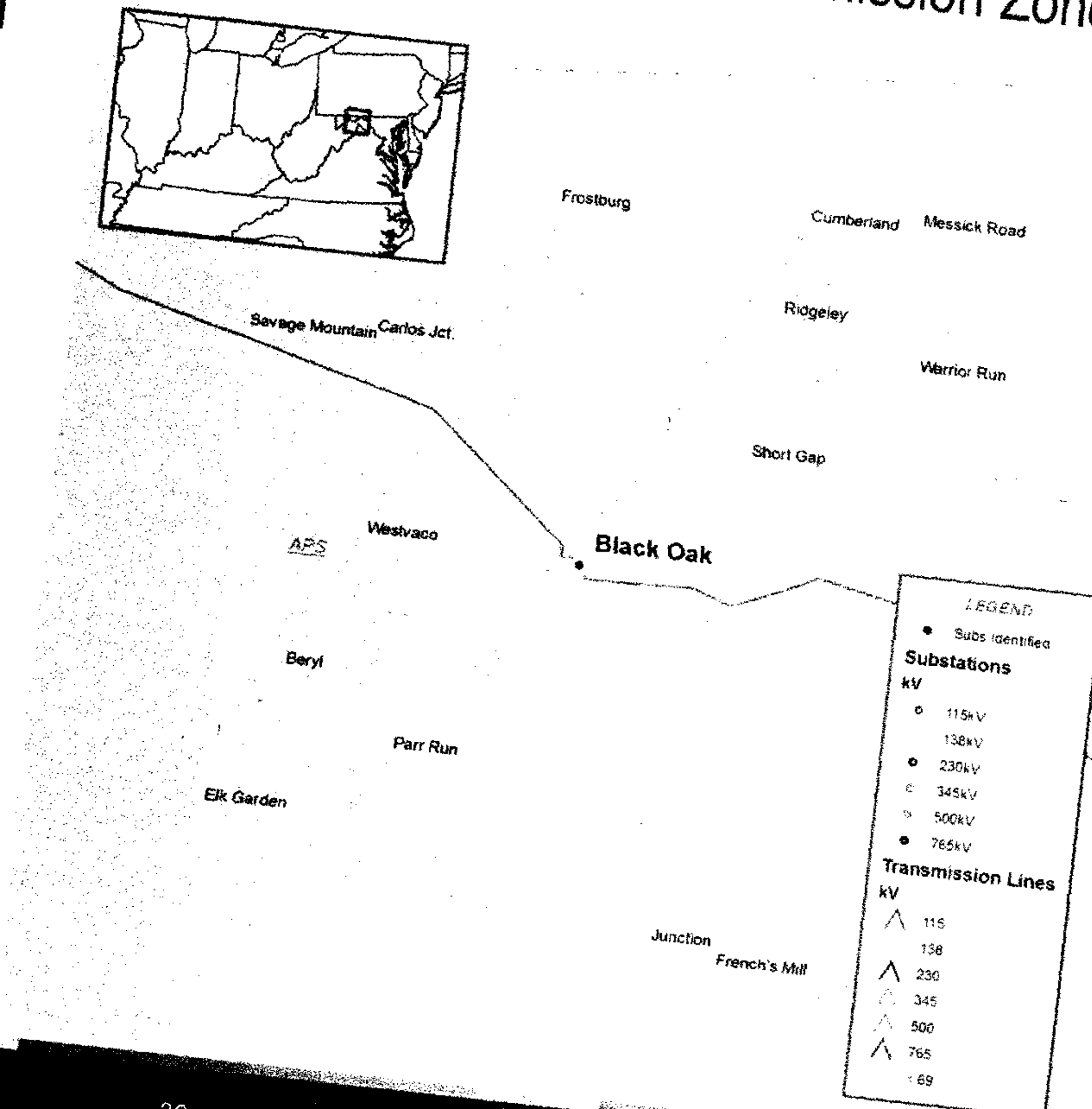
✓ Estimated Project Cost: $0.12M

✓ Expected IS date: 06/01/2016



- Project Withdrawal
  - Cancel Project b1171.3:
    - ✓ Install four 500 kV breakers and remove BOL1 500 kV breaker at Black Oak
    - ✓ Estimated Project Cost: $9.17M
    - ✓ Expected IS Date: 06/01/2013
  - Project no longer required due to updated thermal facility rating

APS Transmission Zone



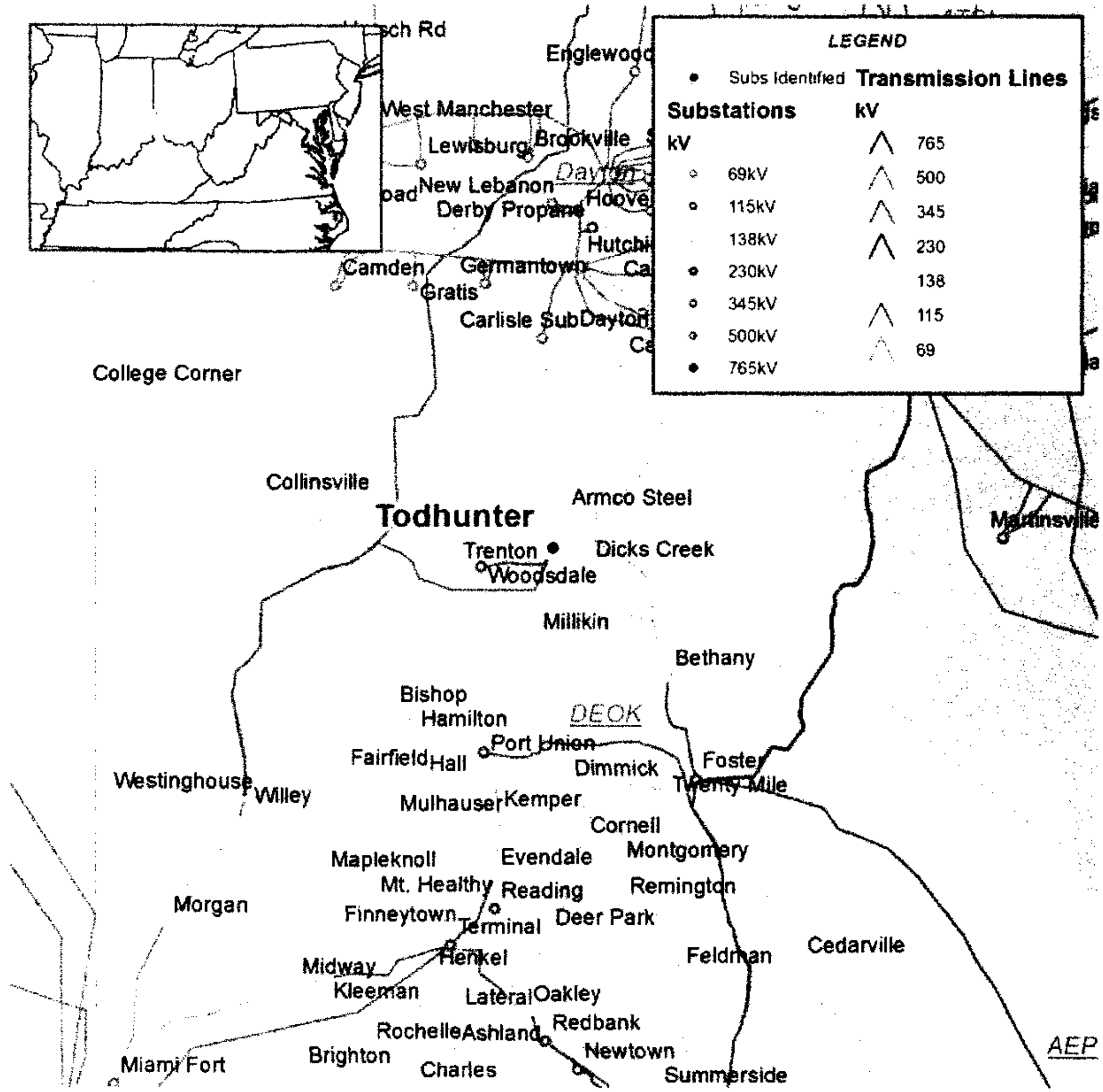
Duke Energy Ohio Kentucky

DEOK Baseline Reliability Summary

- The DEOK zone was considered part of PJM for the 2011 RTEP and current
- Baseline reliability upgrades identified
- Given the integration of the DEOK zone on January 1, 2012 approval of these upgrades will be sought from the PJM Board of Mangers
  - Cost allocation for all DEOK upgrades eligible for PJM Board of Managers approval for inclusion in the RTEP is 100% to the DEOK zone with the exception of the following upgrade:
  - b1707.1 Add a 138/69 kV transformer at Newtown substation
  - b1707.2 Add a new 69 kV line Newtown - Mt. Washington
  - b1707.3 Add a new 69 kV line Newtown - Berkshire
  - b1707.4 Reconfigure the 69 kV loop
    - B1707.1, B1707.2, B1707.3, and B1707.4 are allocated 98.26% to DEOK and 1.74% to Dayton
- The following slides detail the Duke Energy Ohio Kentucky (DEOK) baseline upgrades that will be reviewed with the PJM Board at their April 2012 meeting

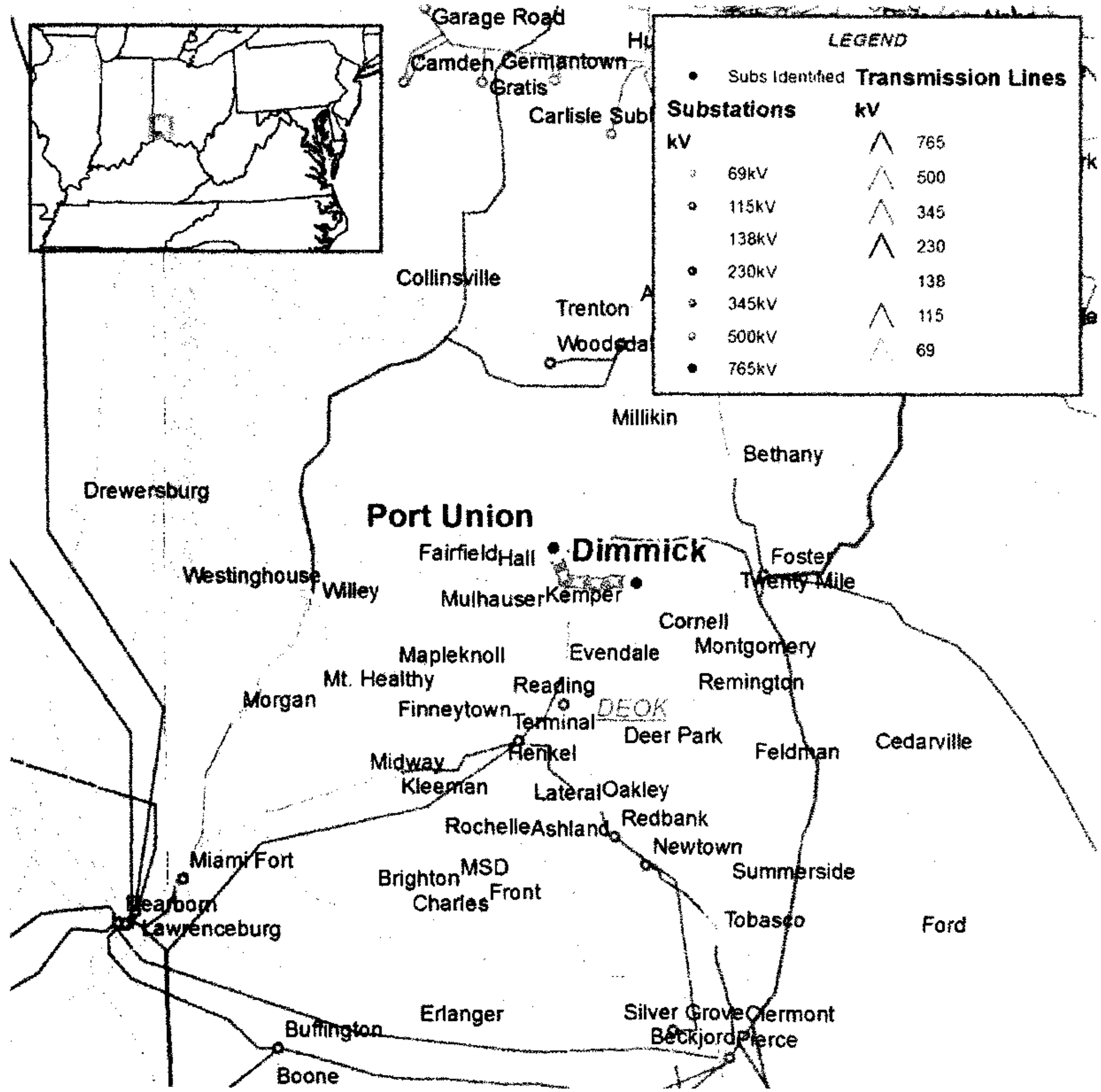
Duke Energy Ohio Kentucky Transmission Zone

- Common Mode Violation
- Todhunter 345/138KV transformers 15 &17 are overloaded for breaker failure operation of the Todhunter 345kV Breaker 1385 or Breaker 1387.
- Recommended Solution:
- Reconfigure the Todhunter 345KV ring bus (B1573)
- Estimated Project Cost: $1.325M
- Expected IS date: 06/01/2014



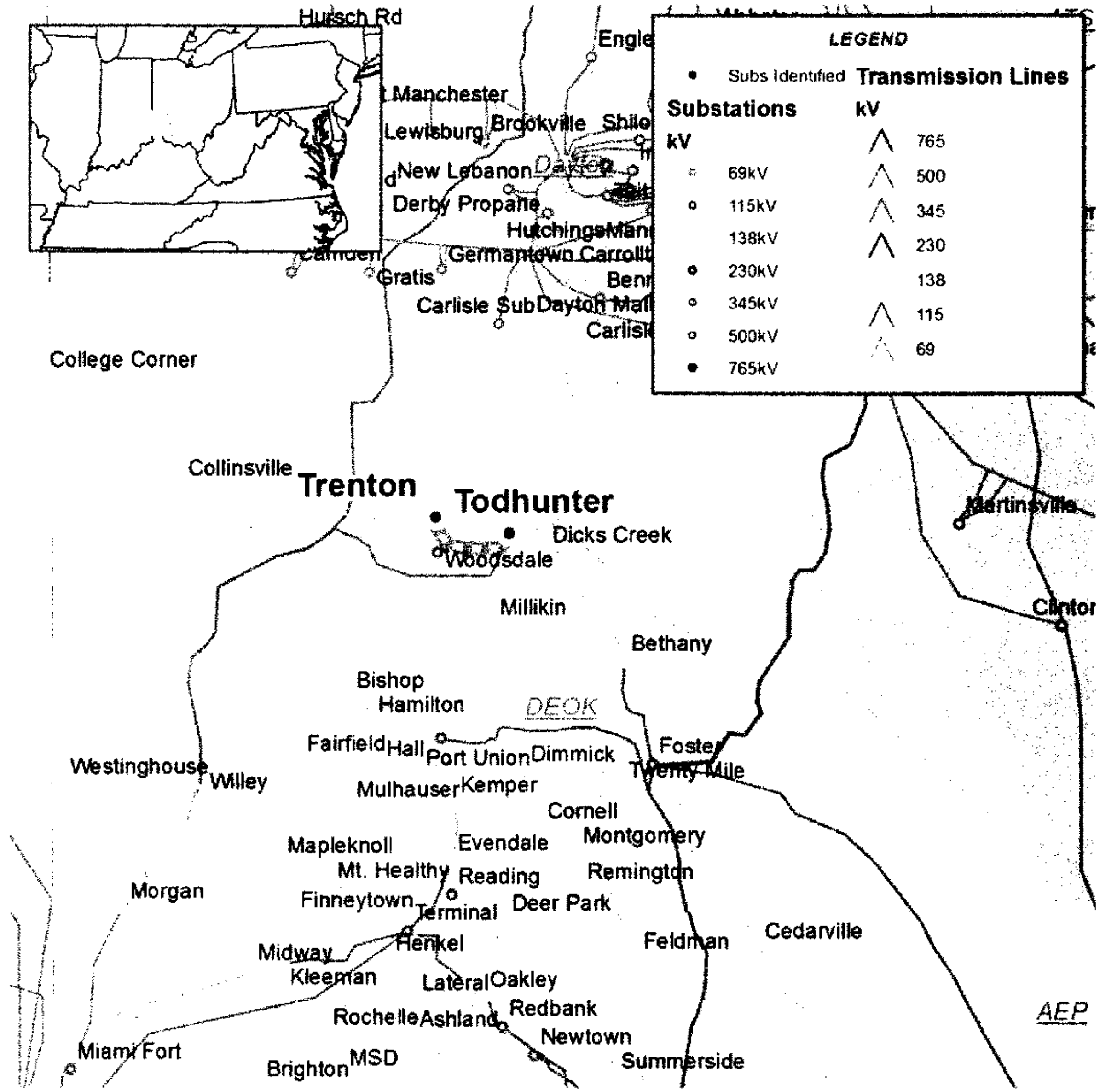
Duke Energy Ohio Kentucky Transmission Zone

- Common Mode Violation
- The Port Union - Dimmick 138kV circuit (#5483) and Dimmick – Cornell Tap 138KV circuit are overloaded for several multiple facility contingencies at Foster 138kV bus.
- Recommended Solution:
- Re-conductor the circuits for 6 miles with 556 ACSS conductor and replace a wavetrap. (B1574)
- Estimated Project Cost: $1.85M
- Expected IS date: 06/01/2014



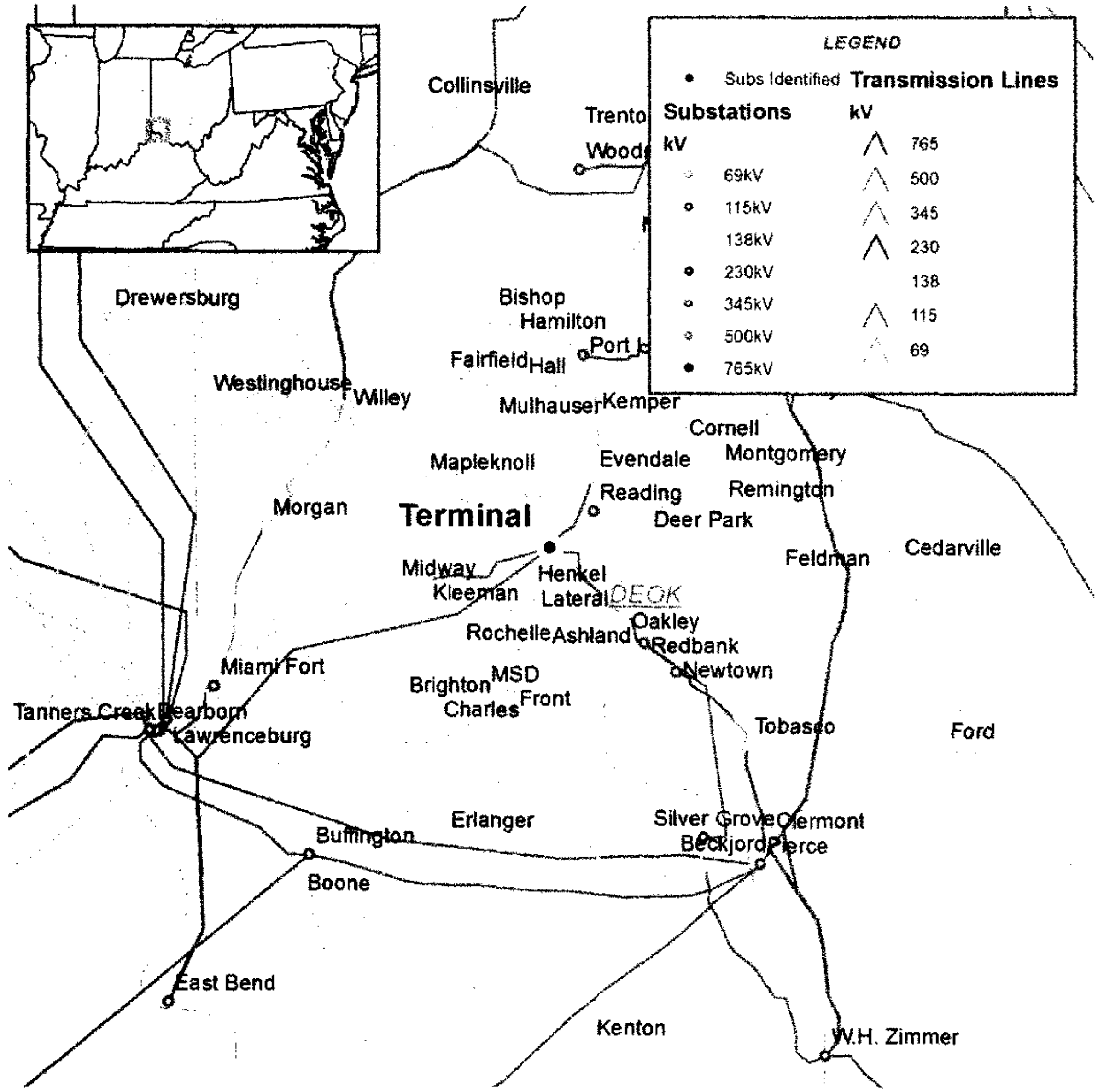
Duke Energy Ohio Kentucky Transmission Zone

- Common Mode Violation
- The Todhunter - Trenton 138kV circuit (#3284) is overloaded for several multiple facility contingencies.
- Recommended Solution:
- Re-conductor the 5 miles circuit with the 556ACSS conductor (B1576)
- Estimated Project Cost: $1.05M
- Expected IS date: 06/01/2013



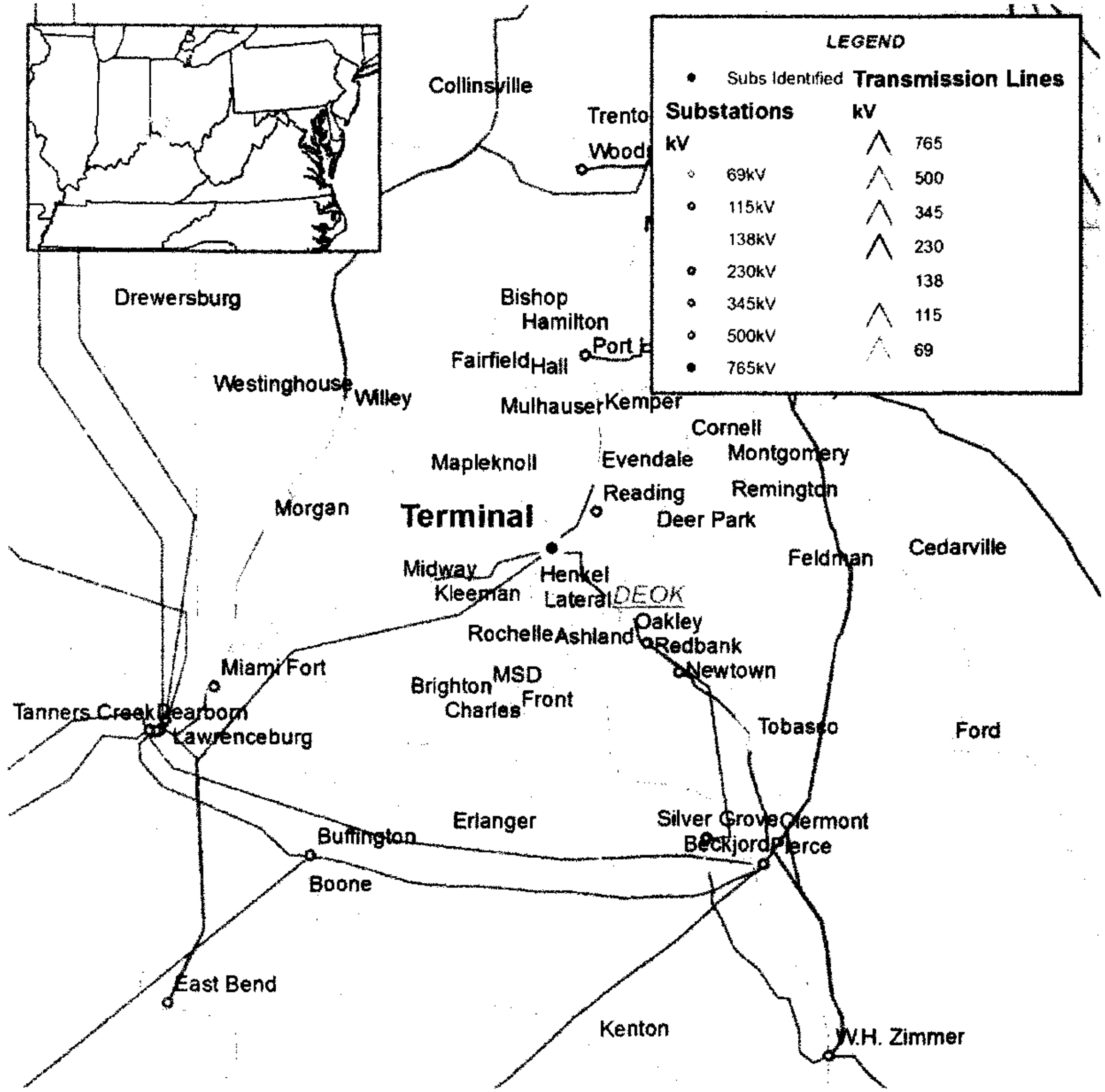
Duke Energy Ohio Kentucky Transmission Zone

- The following breakers are overstressed:
  - Terminal 138 kV breaker „906"
  - Terminal 138 kV breaker „913"
  - Terminal 138 kV breaker „914"
  - Terminal 138 kV breaker „919"
  - Terminal 138 kV breaker „903"
  - Terminal 138 kV breaker „910"
- Proposed Solution:
  - Replace the Terminal 138 kV breaker "906" with 63 kA (b1550)
  - Replace the Terminal 138 kV breaker "913" with 63 kA (b1551)
  - Replace the Terminal 138 kV breaker "914" with 63 kA (b1552)
  - Replace the Terminal 138 kV breaker "919" with 63 kA (b1553)



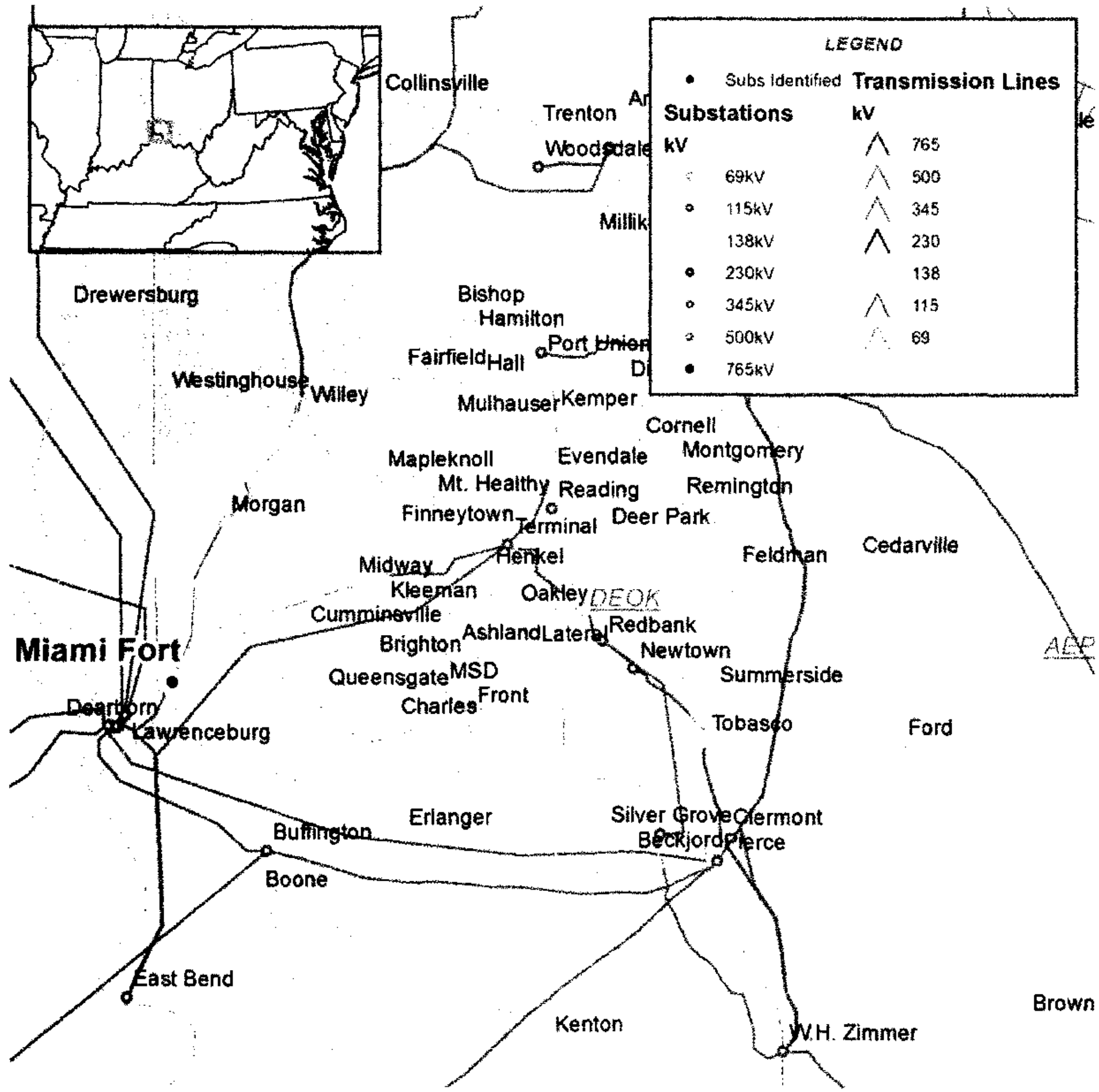
Duke Energy Ohio Kentucky Transmission Zone

- Proposed Solution (cont"d):
  - Revise the reclosing on the Terminal 138 kV breaker „903" to 15 seconds (b1554)
  - Revise the reclosing on the Terminal 138 kV breaker „910" to 15 seconds (b1555)
- Estimated Project Cost:
  - $250 K for each new breaker
  - $0 to revise the reclosing
- Expected IS Date:
  - 12/31/2011 – for breakers 903 and 910
  - 12/31/2012 – for breakers 914 and 919
  - 12/31/2014 – for breakers 913 and 906



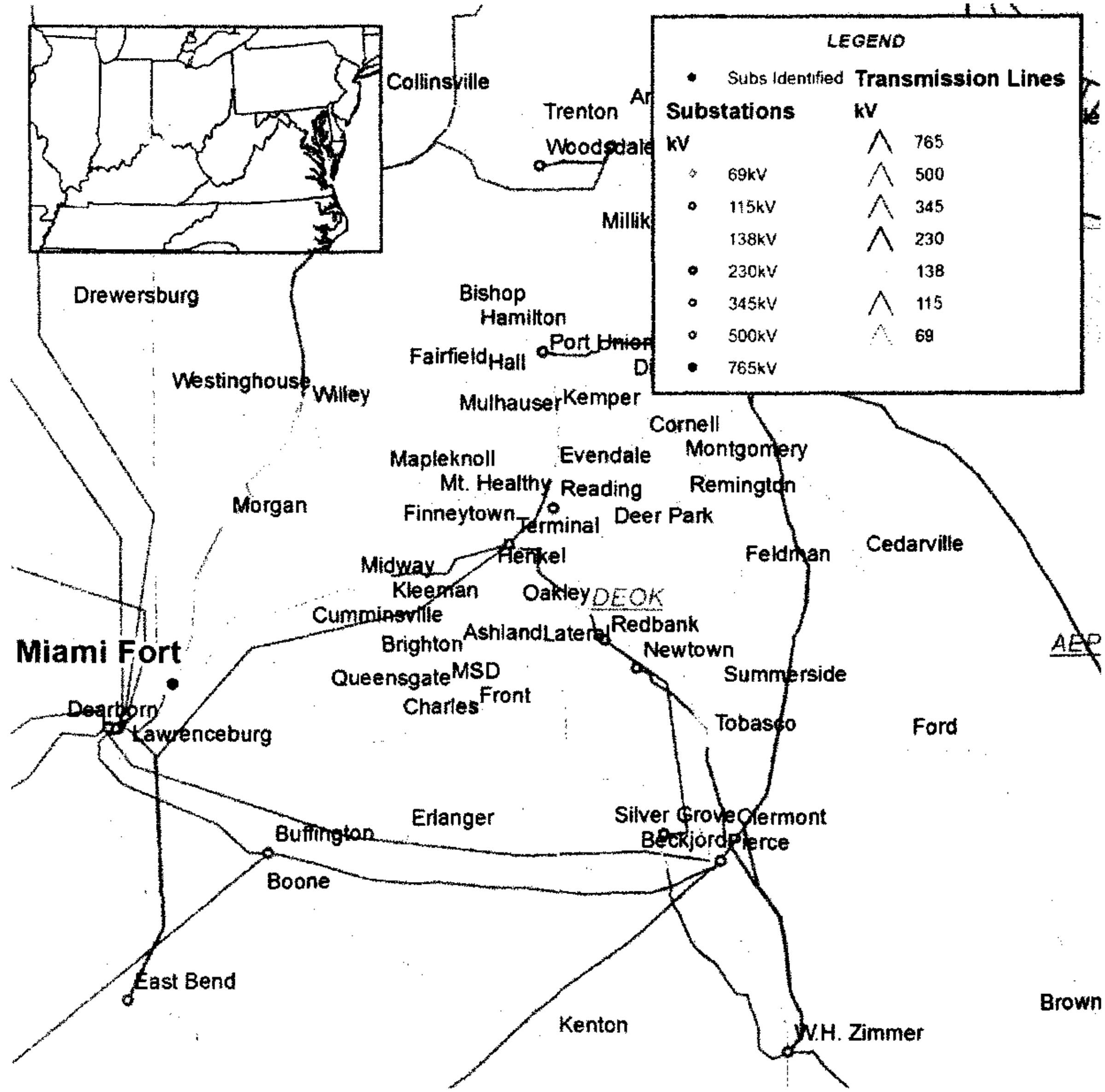
Duke Energy Ohio Kentucky Transmission Zone

- The following breakers are overstressed:
  - Miami Fort 138 kV breaker „804"
  - Miami Fort 138 kV breaker „806"
  - Miami Fort 138 kV breaker „904"
  - Miami Fort 138 kV breaker „928"
  - Miami Fort 138 kV breaker „927"
- Proposed Solution:
  - Replace the Miami Fort 138 kV breaker "804" with 63 kA (b1557)
  - Replace the Miami Fort 138 kV breaker "806" with 63 kA (b1558)
  - Replace the Miami Fort 138 kV breaker "904" with 63 kA (b1559)
  - Replace the Miami Fort 138 kV breaker "928" with 63 kA (b1560)
  - Revise the reclosing on the Miami Fort 138 kV breaker "927" to 15 seconds (b1561)
- Estimated Project Cost:
  - $250 K for each new breaker
  - $0 to revise the reclosing



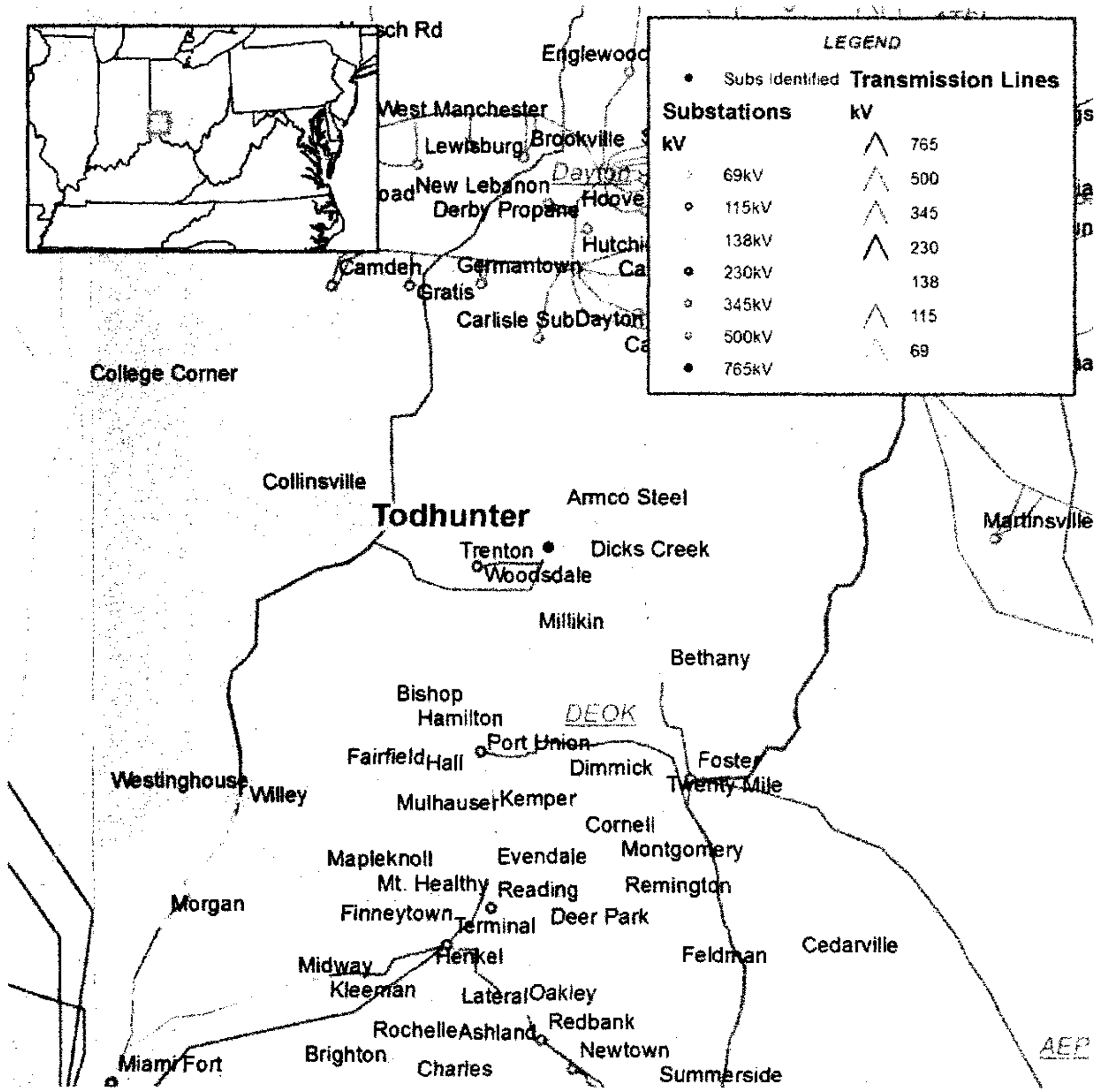
Duke Energy Ohio Kentucky Transmission Zone

- Expected IS Date:
  - 12/31/2011 – for breaker 927
  - 12/31/2012 – for breakers 806 and 928
  - 12/31/2014 – for breakers 804 and 904



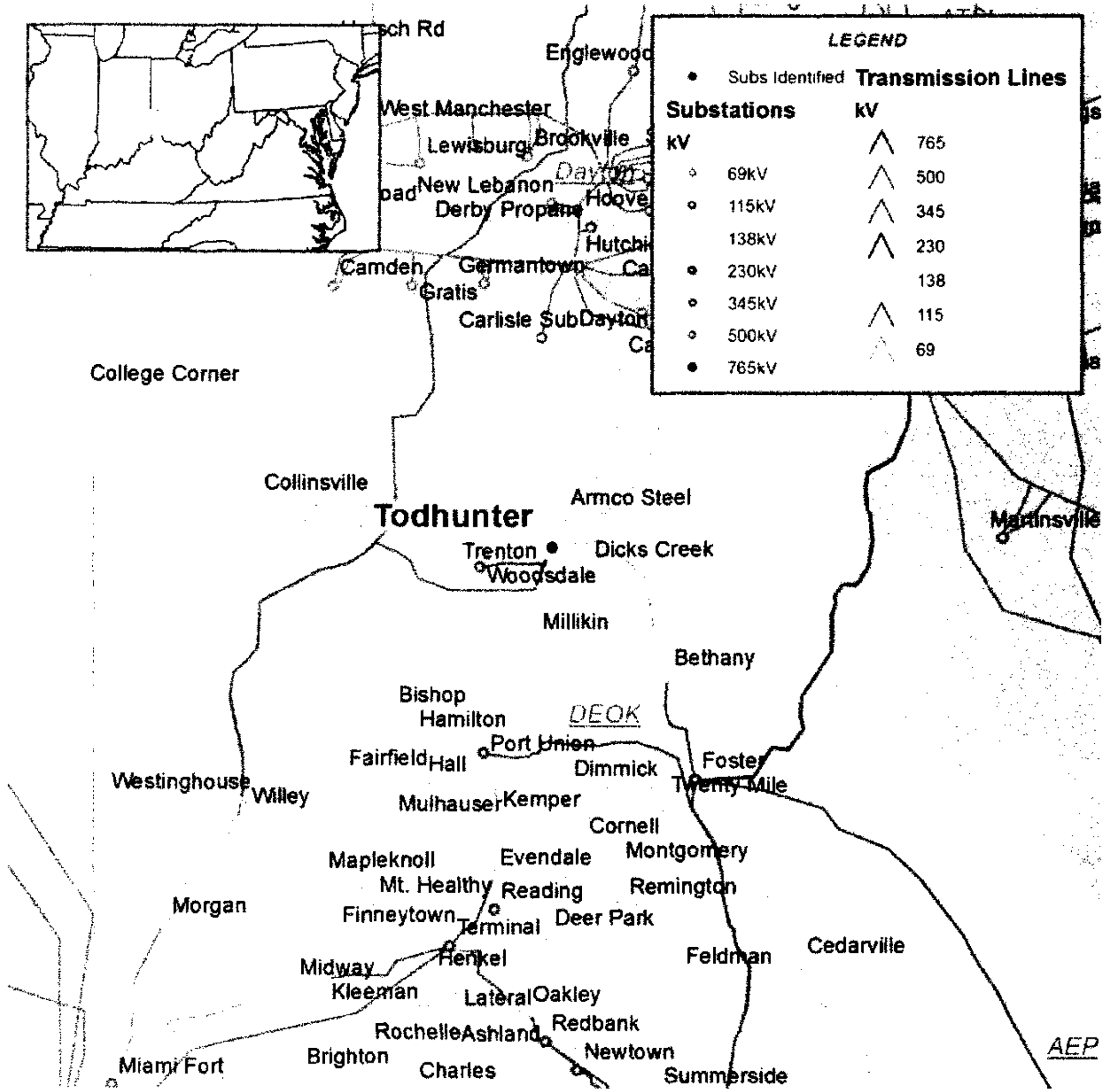
Duke Energy Ohio Kentucky Transmission Zone

- The following breakers are overstressed:
  - Todhunter 138 kV breaker „917"
  - Todhunter 138 kV breaker „919"
  - Todhunter 138 kV breaker „923"
  - Todhunter 138 kV breaker „927"
  - Todhunter 138 kV breaker „929"
  - Todhunter 138 kV breaker „931"
  - Todhunter 138 kV breaker „937"
  - Todhunter 138 kV breaker „911"
- Proposed Solution:
  - Replace the Todhunter 138 kV breaker "917" with 63 kA (b1562)
  - Replace the Todhunter 138 kV breaker "919" with 63 kA (b1563)
  - Replace the Todhunter 138 kV breaker "923" with 63 kA (b1564)
  - Replace the Todhunter 138 kV breaker "927" with 63 kA (b1565)
  - Replace the Todhunter 138 kV breaker "929" with 63 kA (b1566)
  - Replace the Todhunter 138 kV breaker "931" with 63 kA (b1567)
  - Replace the Todhunter 138 kV breaker "937" with 63 kA (b1568)



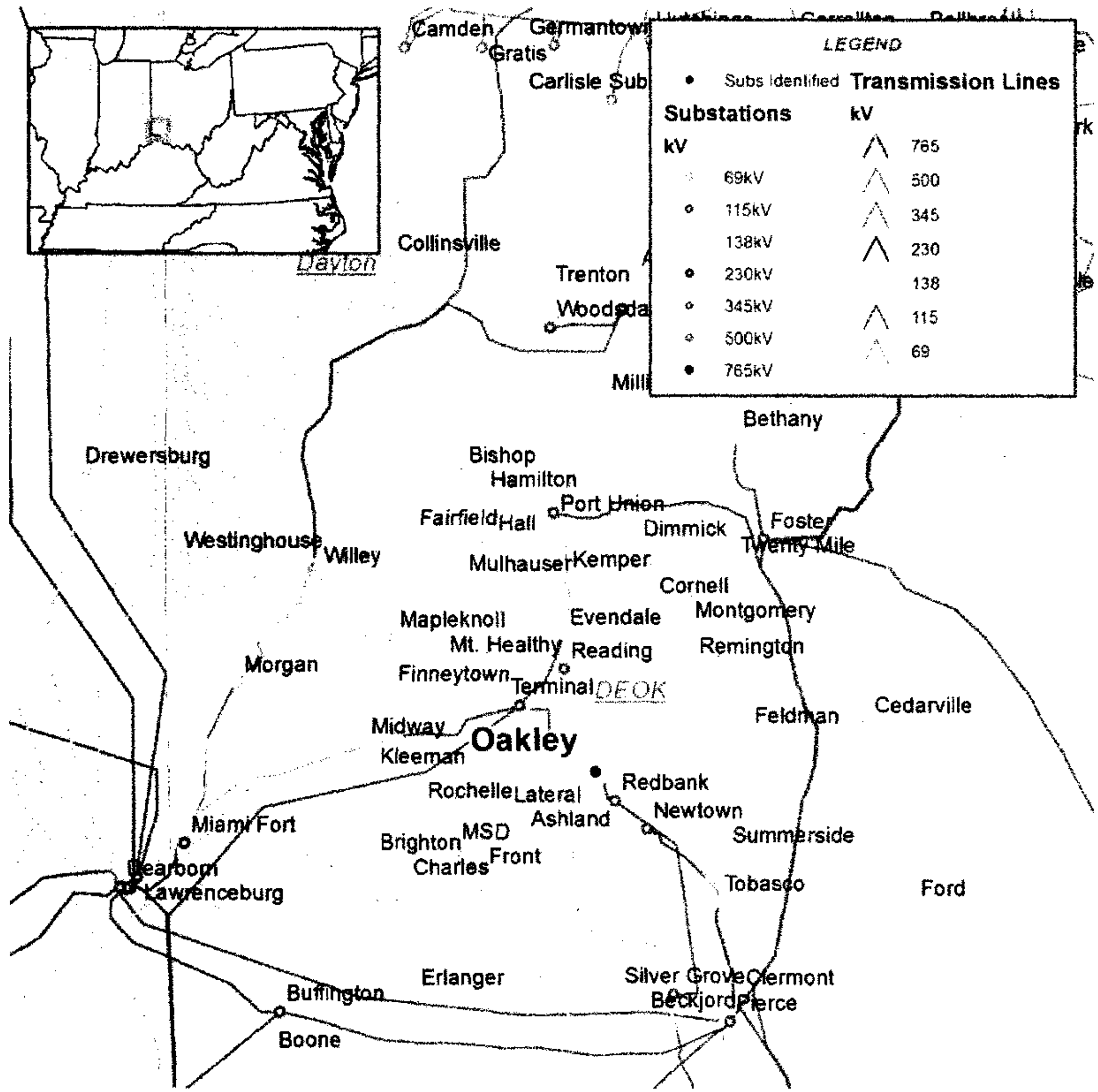
Duke Energy Ohio Kentucky Transmission Zone

- Proposed Solution (cont"d):
  - Revise the reclosing on the Todhunter 138 kV breaker "911" to 15 seconds (b1569)
- Estimated Project Cost:
  - $250 K for each new breaker
  - $0 to revise the reclosing
- Expected IS Date:
  - 12/31/2011 – for breaker 911
  - 12/31/2012 – for breakers 927, 929, and 937
  - 12/31/2013 – for breakers 931, 919, 917, and 923



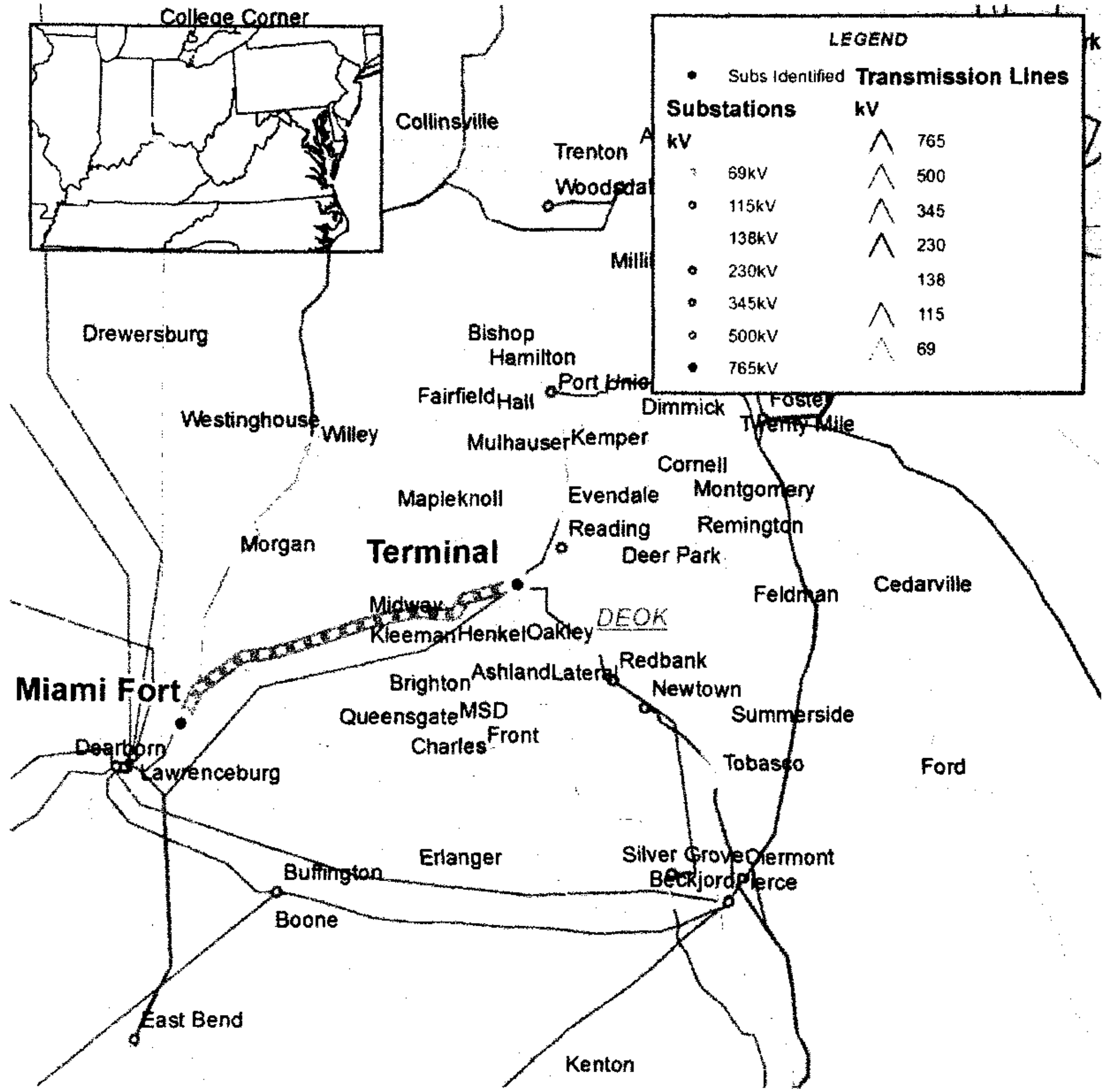
Duke Energy Ohio Kentucky Transmission Zone

- The following breakers are overstressed:
  - Oakley 138 kV breaker „805"
- Proposed Solution:
  - Replace the Oakley138 kV breaker "805" with 63 kA (b1556)
- Estimated Project Cost:
  - $250 K
- Expected IS Date: 12/31/2014



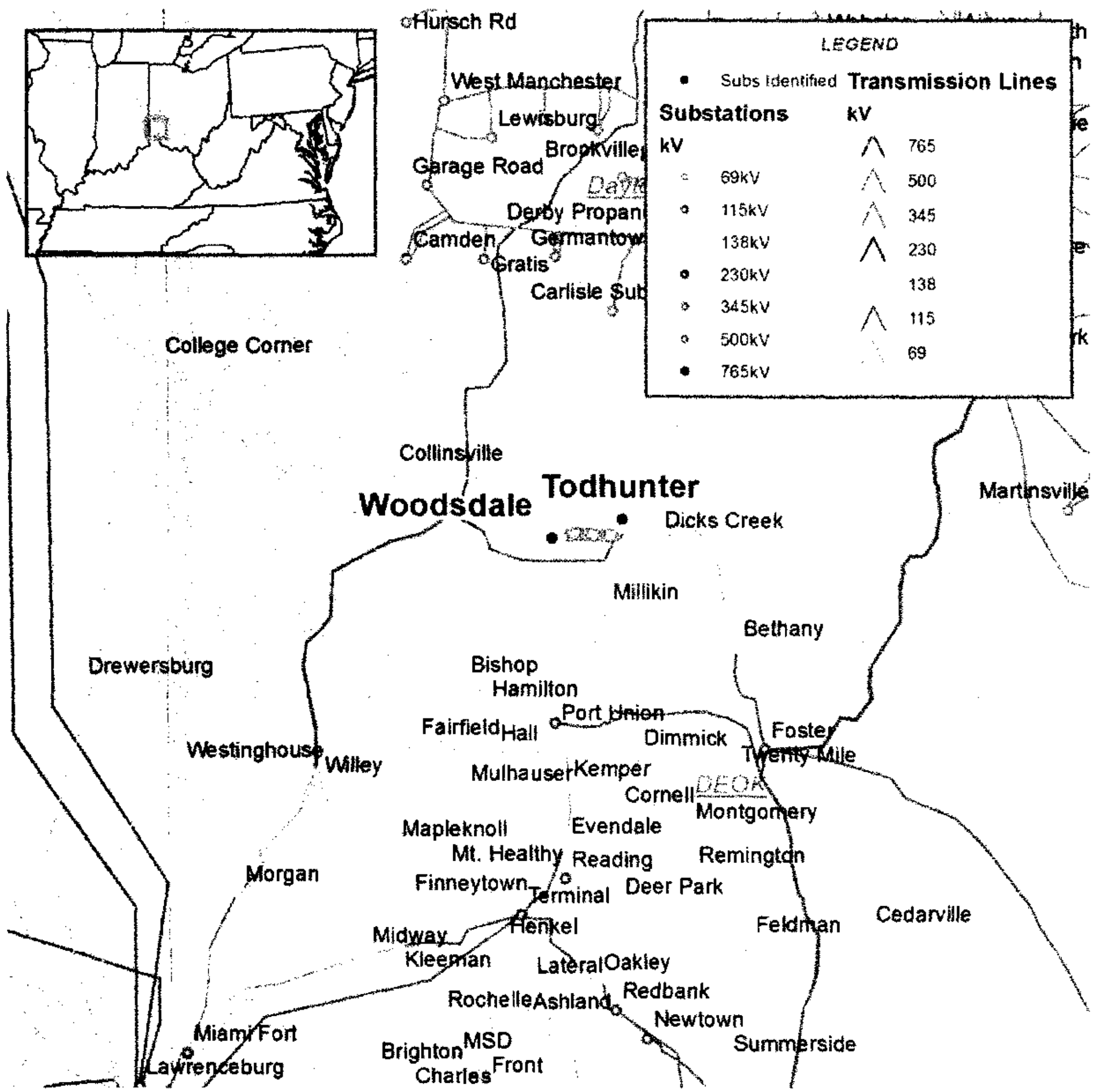
Duke Energy Ohio Kentucky Transmission Zone

- Common Mode Violation
- The Circuit 4515 Miami Fort - Terminal 345kV circuit is overloaded for the tower contingency of losing both circuit #4561and circuit #4562
- Recommended Solution:
- Replace wavetrap and line switch (B1704)
- Estimated Project Cost: $0.104M
- Expected IS date: 06/01/2013



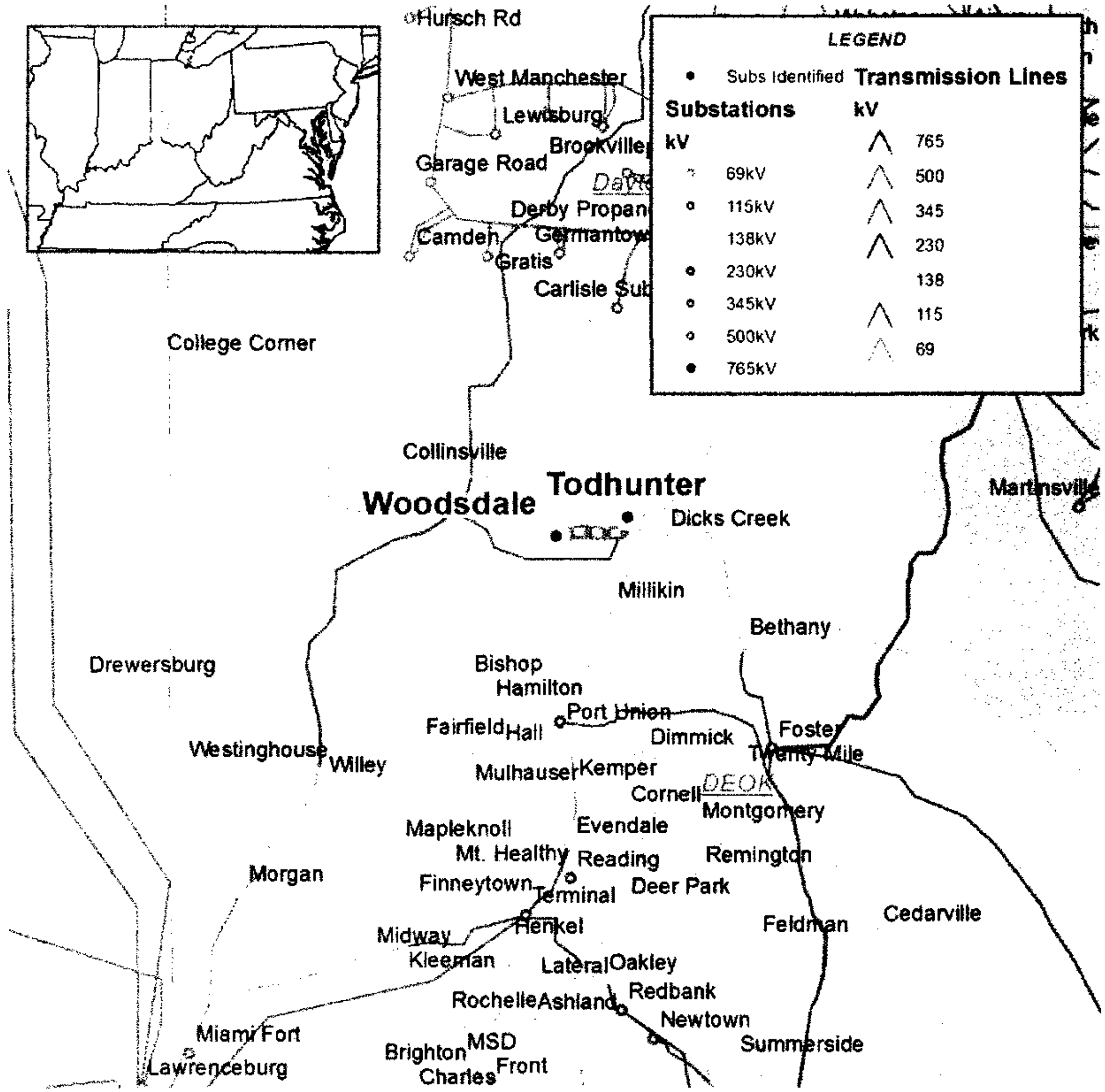
Duke Energy Ohio Kentucky Transmission Zone

- Generator Deliverability Violation
- The circuit 4561 Woodsdale - Todhunter 345kV circuit is overloaded for the loss of circuit #4562
- Recommended Solution:
- Replace wavetraps and line switches (B1705)
- Estimated Project Cost: $0.21M
- Expected IS date: 06/01/2013



Duke Energy Ohio Kentucky Transmission Zone

- Generator Deliverability Violation
- The circuit 4562 Woodsdale - Todhunter 345kV circuit is overloaded for the loss of circuit #4561
- Recommended Solution:
- Replace wavetraps and line switches (B1706)
- Estimated Project Cost: $0.21M
- Expected IS date: 06/01/2013



Duke Energy Ohio Kentucky Transmission Zone

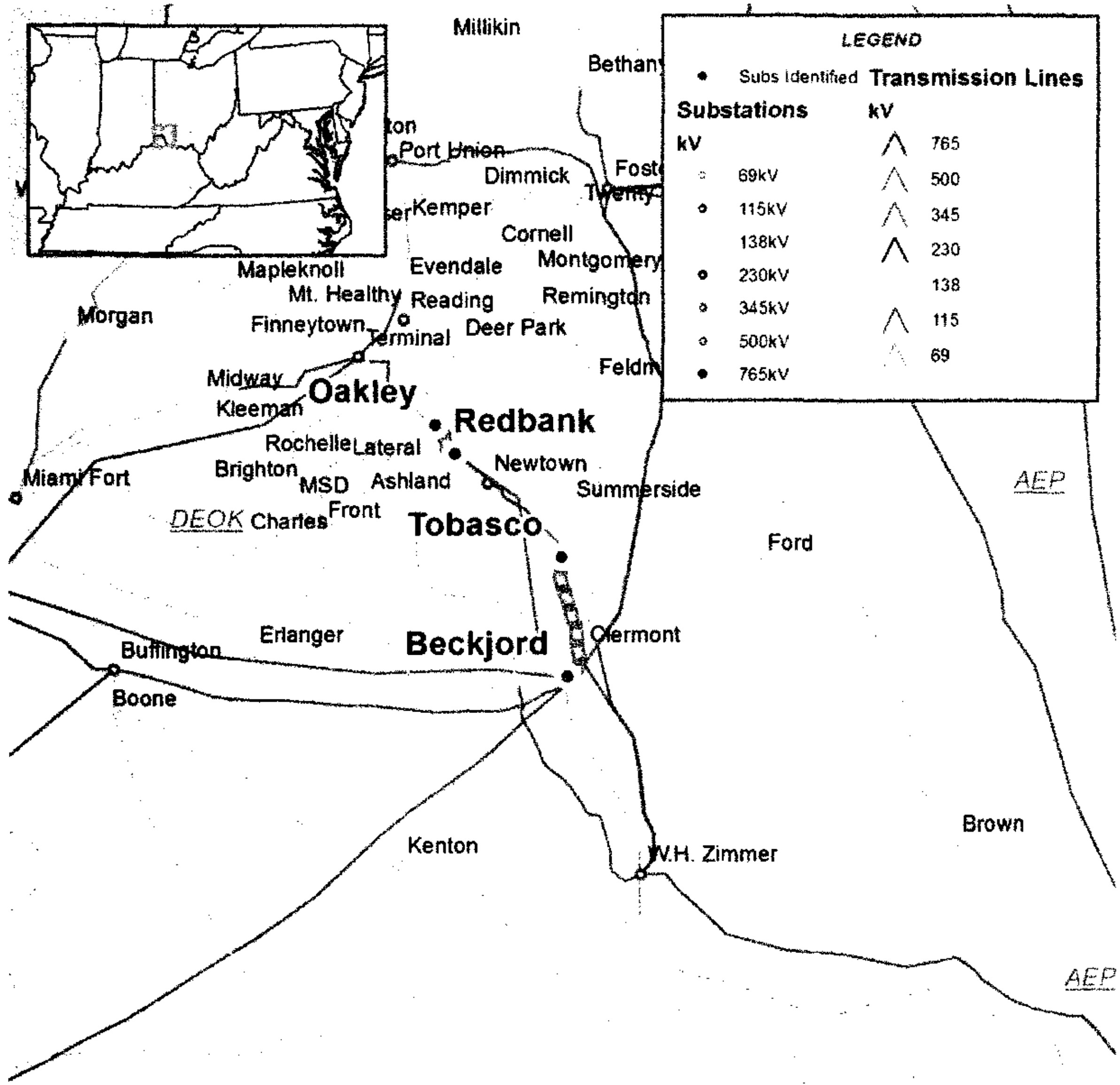
- Common Mode Violation

- The Berjord - Tobasco 138kV circuit (#1885) is overloaded for several multiple facility contingencies;
- The Red Bank - Oakley 138kV circuit (#885) is overloaded for several multiple facility contingencies.

- Recommended Solution:
- - Add a 138/69kV transformer at Newtown substation (B1707.1)
  - Add a new 69kV line Newtown – Mt. Washington B1707.2)
  - Add a new 69kV line Newtown – Berkshire (B1707.3)
  - Reconfigure the 69kV loop (B1707.4)

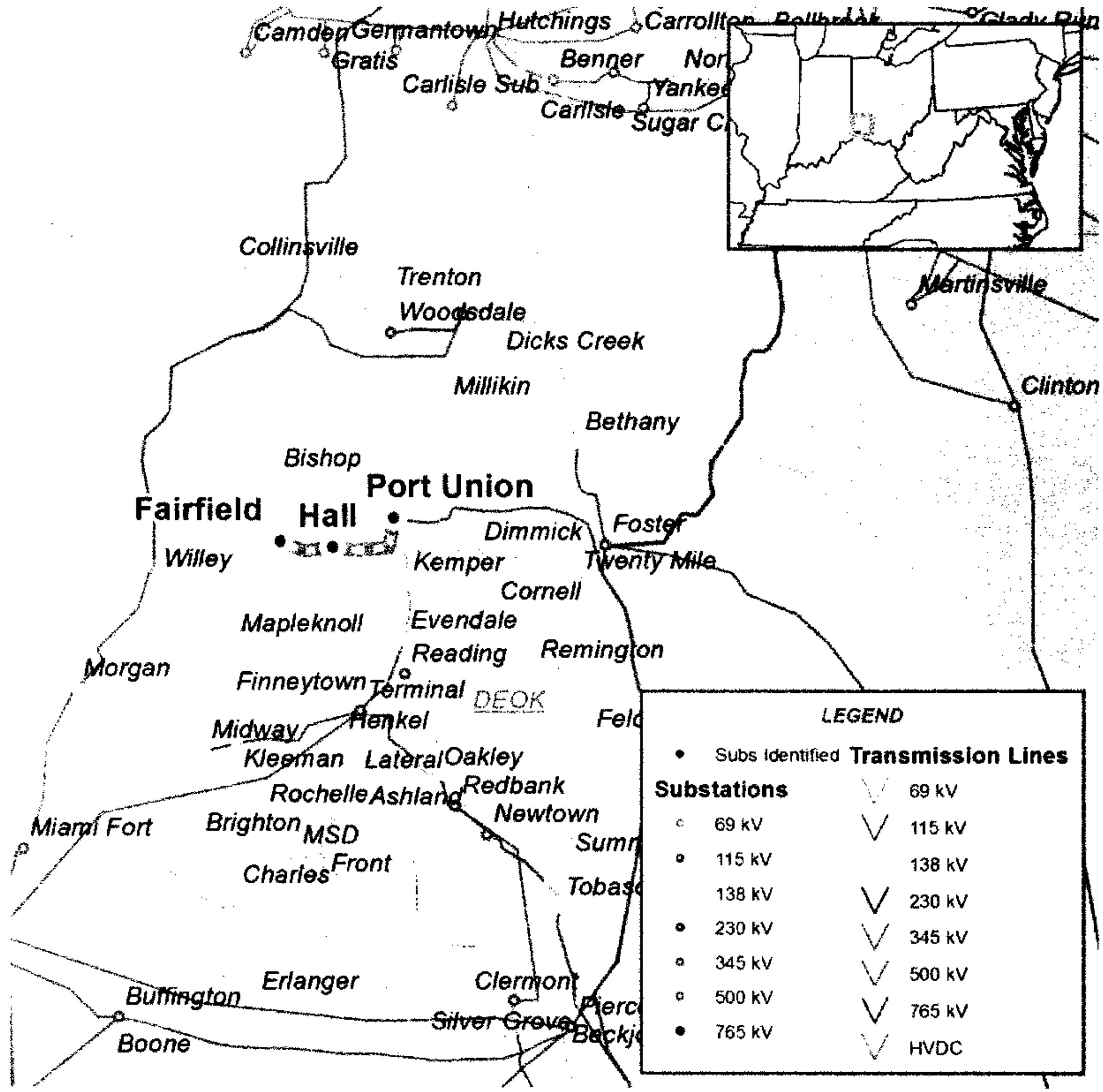
- Estimated Project Cost: $8M

- Expected IS date: 06/01/2014



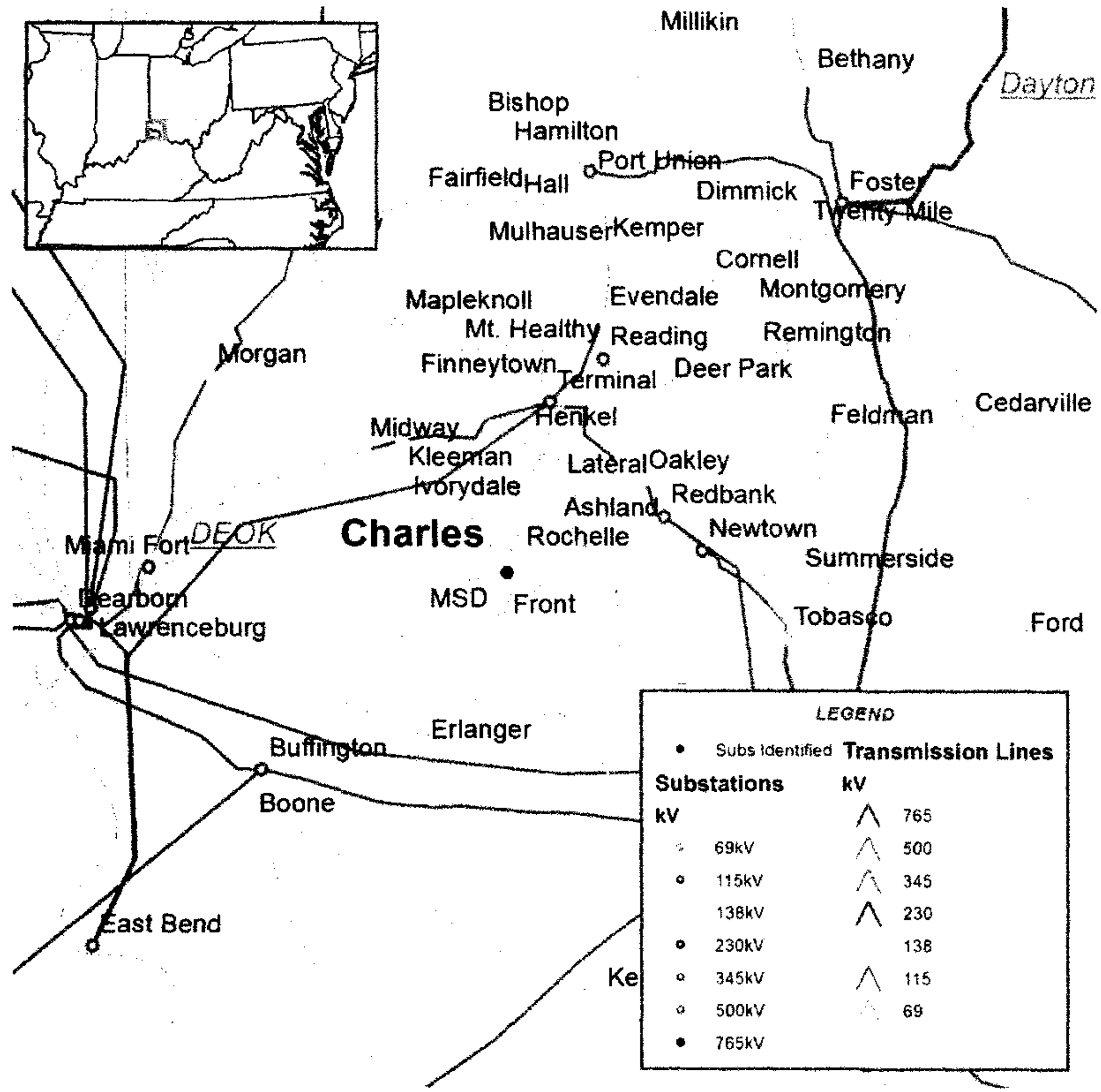
Duke Energy Ohio Kentucky Transmission Zone

- N-1-1 Thermal Violation
- Port Union – Hall – Fairfield 138kV line is overload for the loss of circuit 1689 and circuit 3889.
- Create a ring at Fairfield 138kV substation (B1726)
- Split Circuit 3886 (Willey – Mulhauser 138kV) and land both ends in Fairfield (B1726.1)
- Close circuit 9787 (Willey – Mapleknoll - Mt Healthy – Finneytown – Terminal 138kV), which runs normally open at Mt Healthy (B1726.2)
- Estimated Project Cost: $4M
- Expected IS Date: 6/1/2016



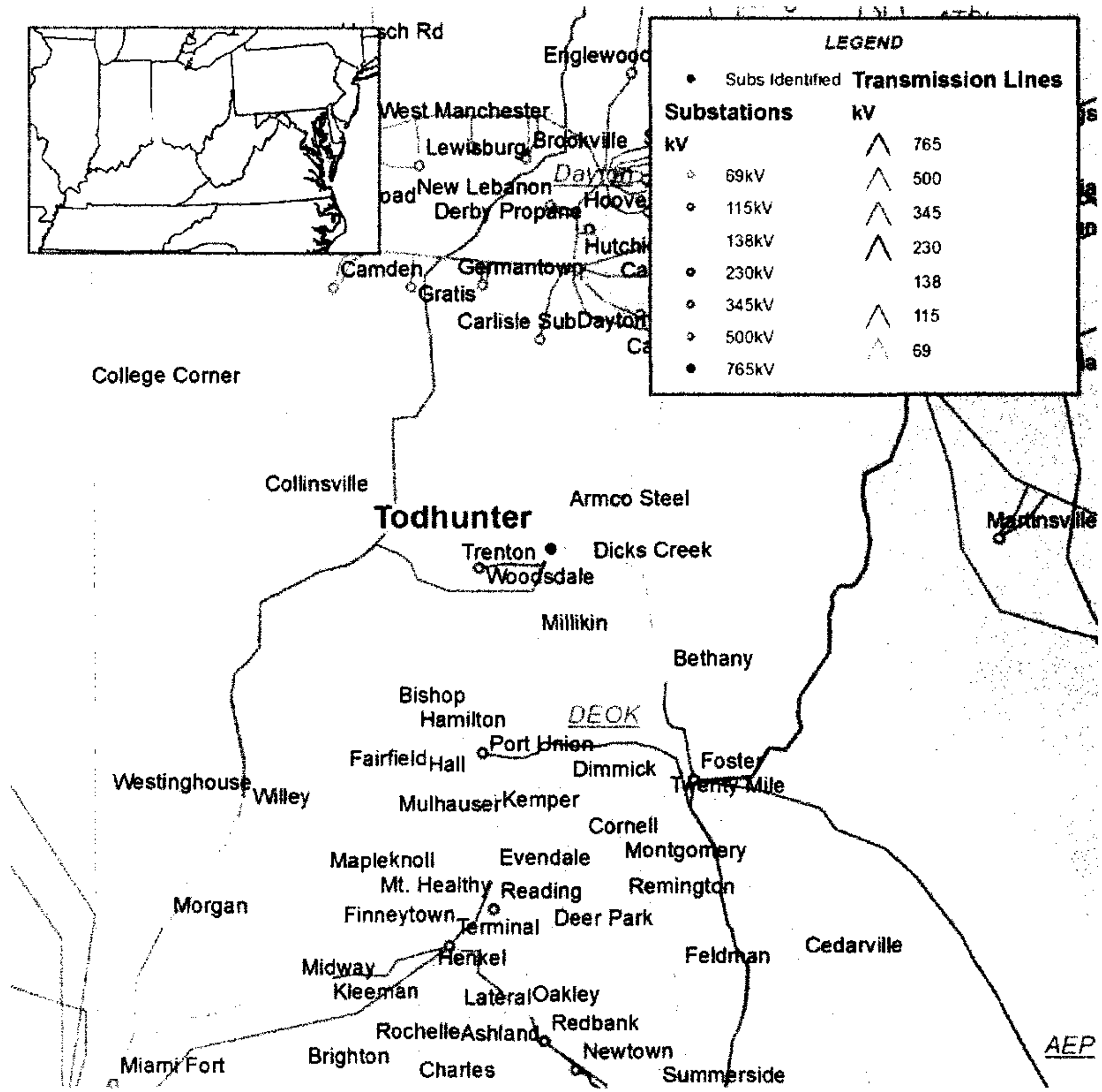
Duke Energy Ohio Kentucky Transmission Zone

- The Charles 138kV breakers „921„ „905," and „917" are overstressed
- Proposed Solution: Replace Charles 138kV breakers „921„ „905," and „917" (b1641-b1643)
- Estimated Project Cost: $250 K per breaker
- Expected IS Date: 6/1/2013



Duke Energy Ohio Kentucky Transmission Zone

- The Todhunter 138kV breaker „925" is overstressed
- Proposed Solution: Revise the reclosing for Todhunter 138kV breaker „925" (b1644)
- Expected IS Date: 6/1/2016



Short Circuit

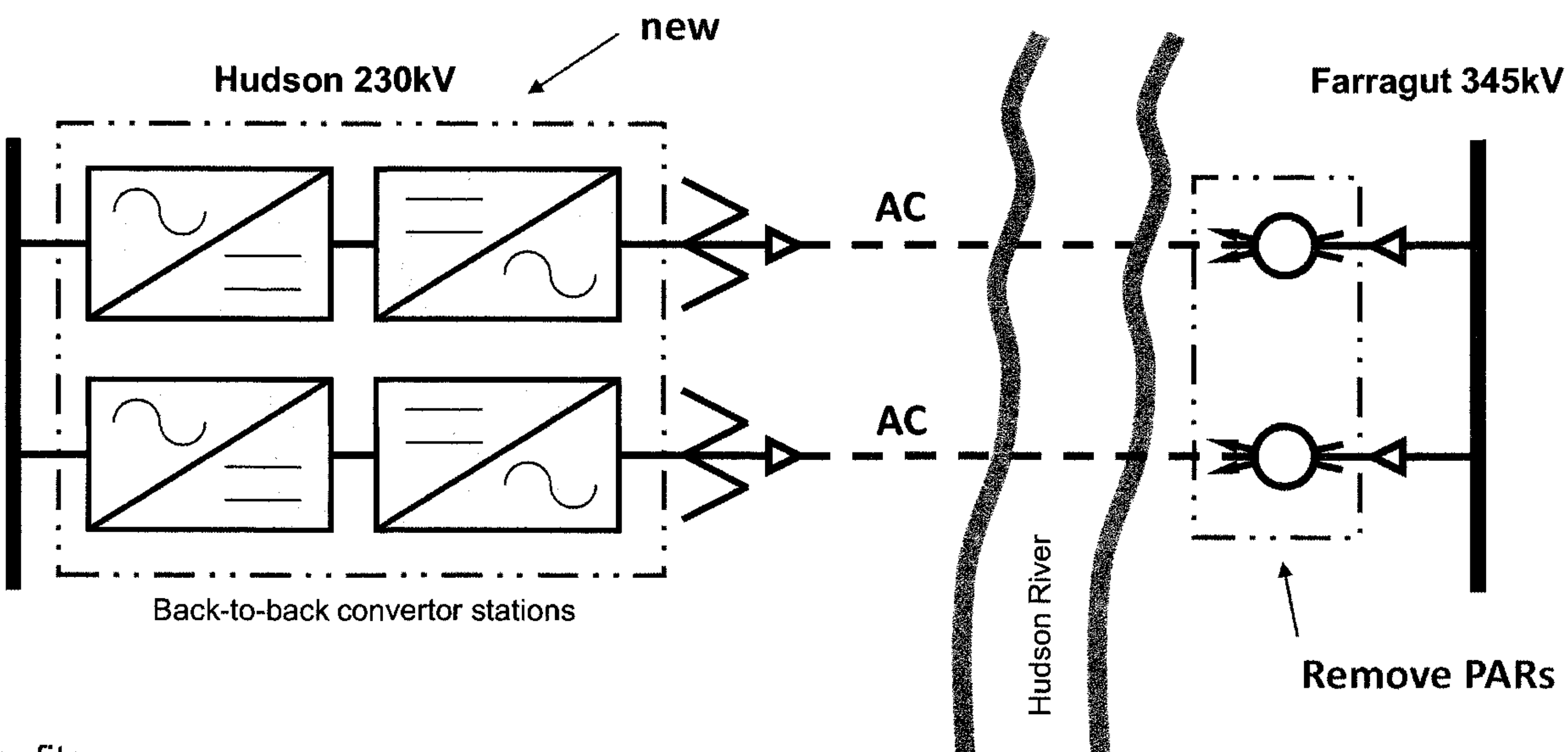
Short Circuit Fault Duty Near PSEG / ConEd Interface

- Problem: Simulated fault duty exceeding 80 kV near the PSEG / ConEd interface

- Potential solution for consideration:
  - Reduce short-circuit levels at Hudson by 15kA by converting the PSE&G to ConEd interconnection from AC to DC
    - ✓ Alternative 1: Back-to-Back DC Conversion
    - ✓ Alternative 2: Simplified DC Conversion

Short Circuit Fault Duty Near PSEG / ConEd Interface

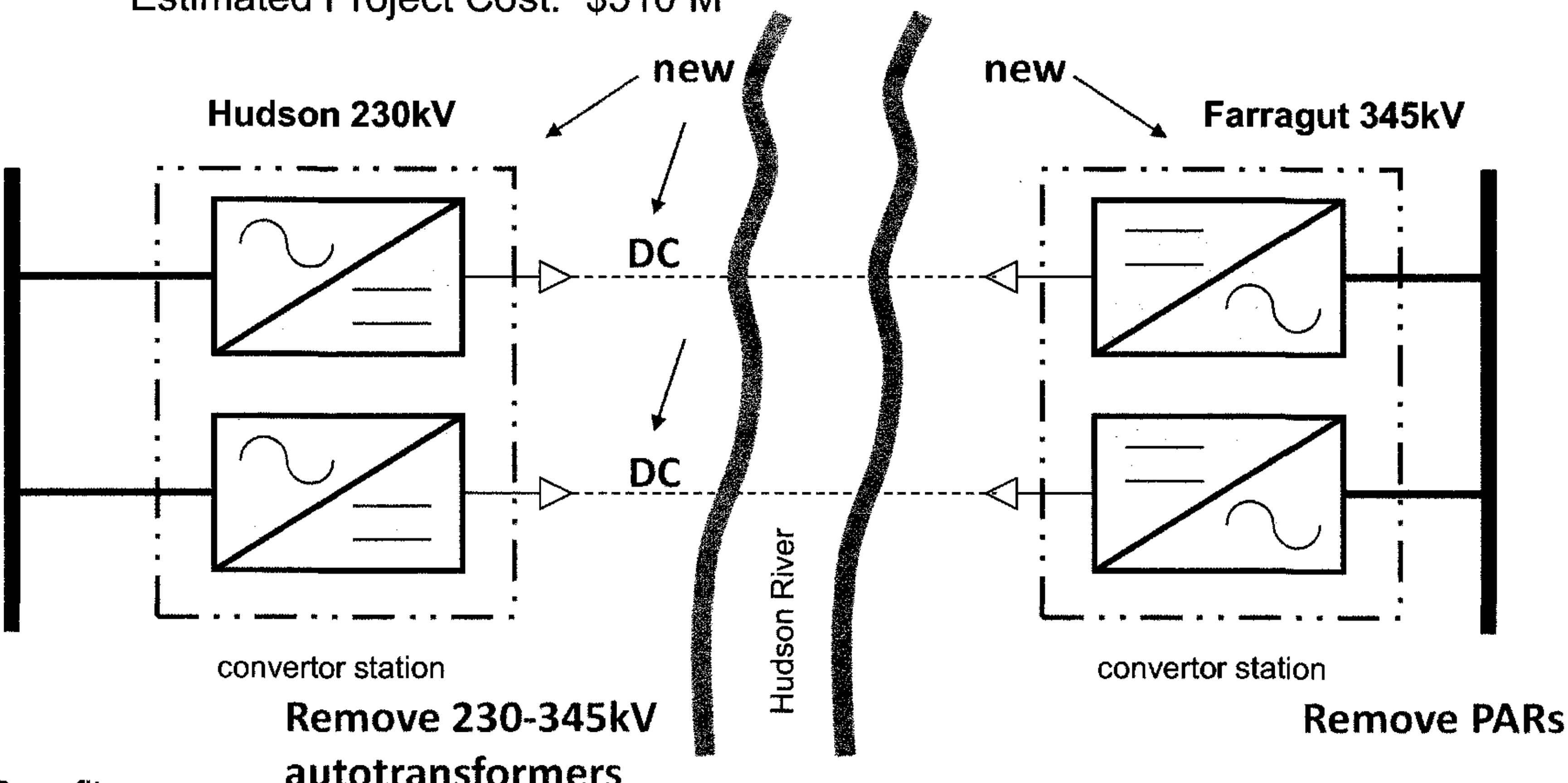
Alternative 1: B-3402 & C-3403 would remain AC
Estimated Project Cost: $300 M



Benefits:
1) Resolves short-circuit problems at Hudson and ConEd
2) Provides more controllability

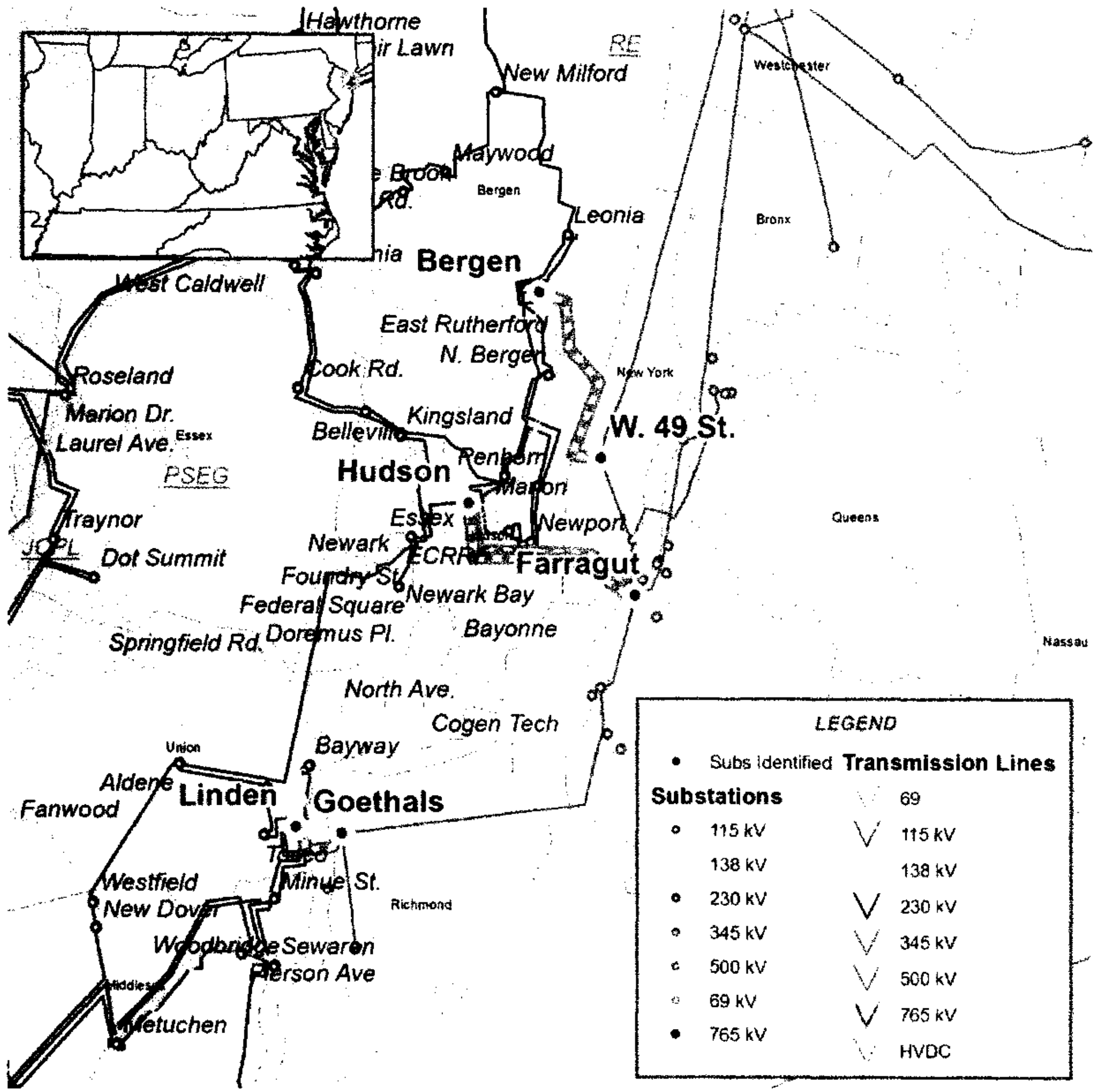
Short Circuit Fault Duty Near PSEG / ConEd Interface

Alternative 2: Two HVDC circuits would replace B-3402 & C-3403
Estimated Project Cost: $510 M



Benefits:
1) Resolves short-circuit problems at Hudson and ConEd
2) Provides much better controllability on the B&C circuits

New York City Interface



Supplemental Projects

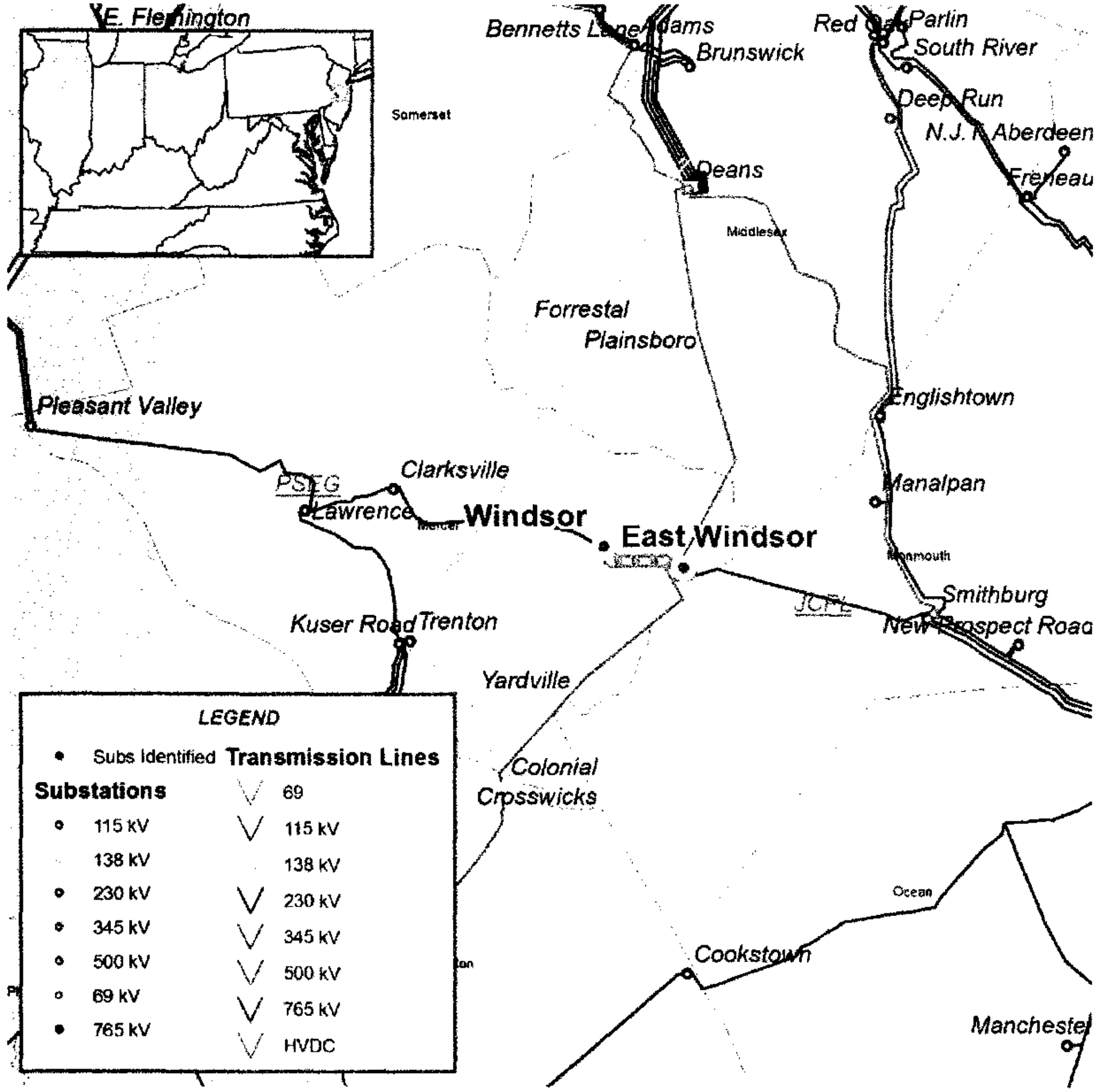
JCP&L Transmission Zone

- To improve reliability.
- Loss of the Deans - E. Windsor 500kV (V5022) line and E. Windsor – Smithburg 230kV (E2005) line overloads the E. Windsor - Windsor 230kV (F2006) circuit.
- Proposed Solution:

  Windsor Sub - Replace substation conductor and CTs on E. Windsor (F2006) 230kV Line Terminal (S0394).
- Estimated Project Cost:

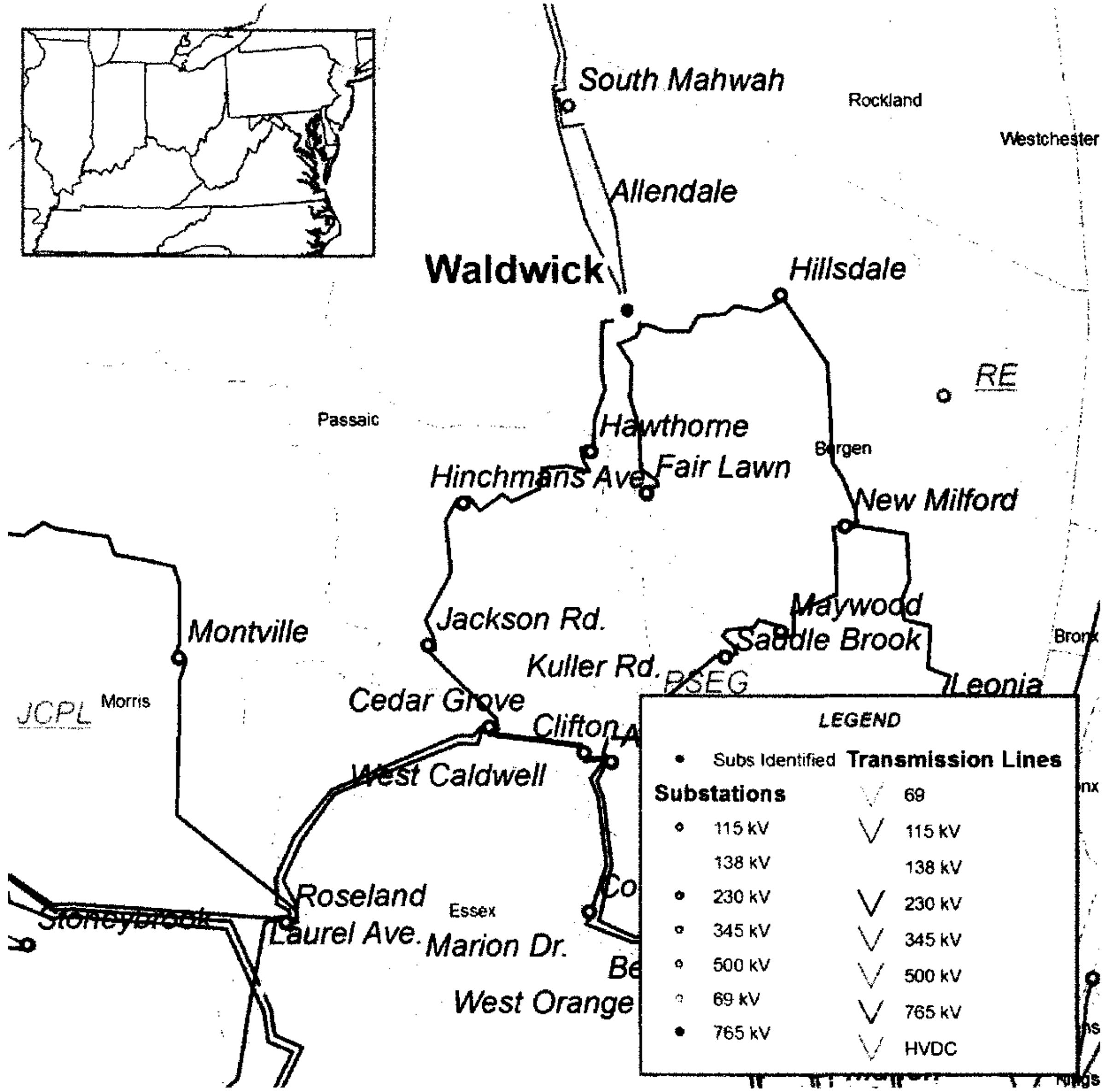
  $ 0.1186 M
- Expected IS Date:

  6/1/2012



PSE&G Transmission Zone

- PSE&G Reliability:
- To improve reliability due to failure of the Waldwick Phase Angle Regulator (E-2257).
- Replace the Waldwick Phase Angle Regulator (E-2257) (S0383).
- Estimated Project Cost: $ 30 M
- Expected IS Date: 2012 -2013



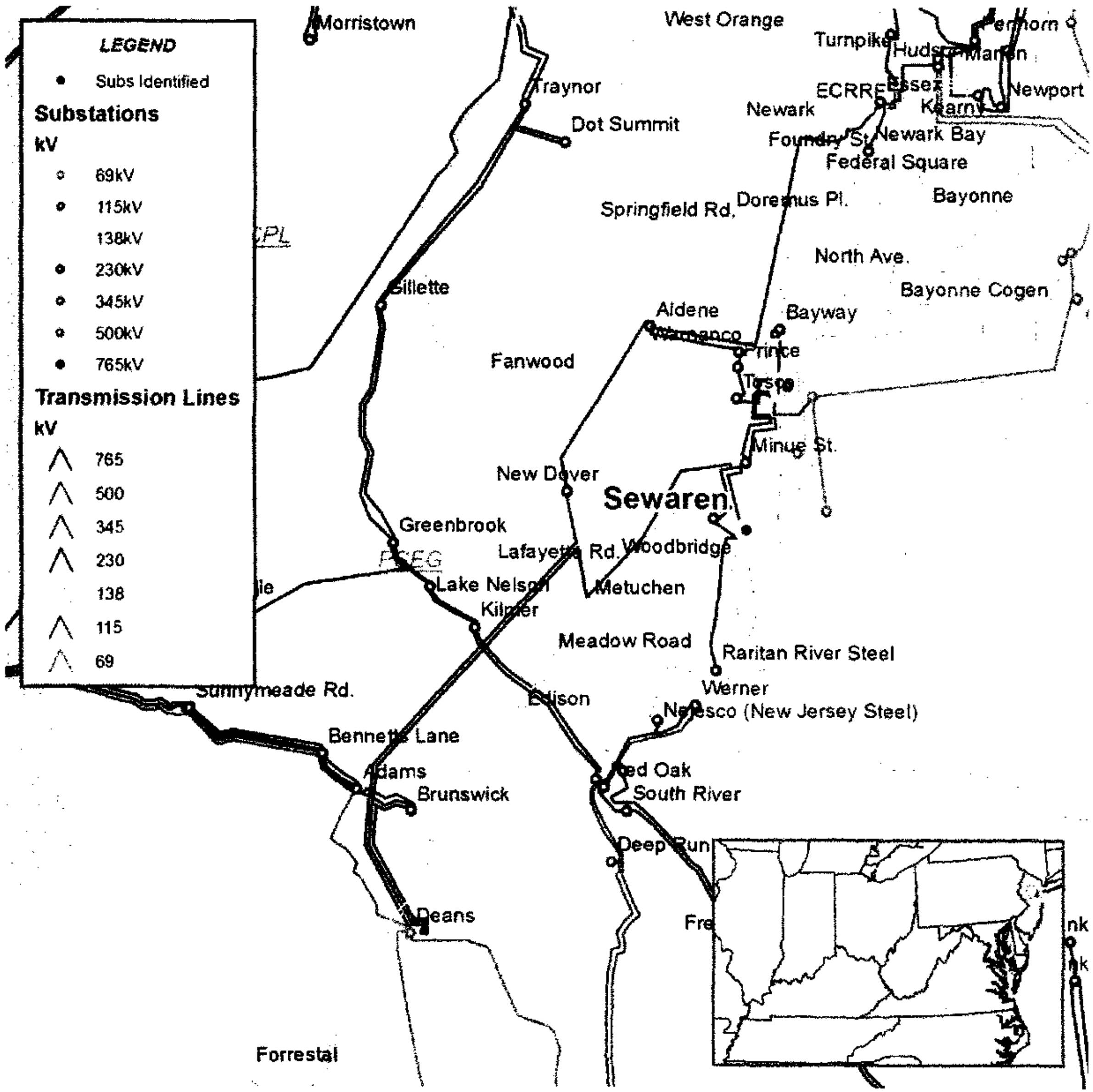
PSE&G Transmission Zone

- PSE&G Reliability:
- Static Wire Replacement is an on-going program that entails replacing aged tower static wires with a new approach, installing static wire with Optical Guide Wire (OPGW). This provides strength, lightning protection and a potential communications path for high speed relaying.
- Replace static wire at the following location

  Sewaren – Linden 230 kV corridor (S0384).
- Estimated Project Cost:

  $ 3 M
- Expected IS Date:

  10/1/2013



PSE&G Transmission Zone

- PSE&G Reliability:
- Static Wire Replacement is an on-going program that entails replacing aged tower static wires with a new approach, installing static wire with Optical Guide Wire (OPGW). This provides strength, lightning protection and a potential communications path for high speed relaying.
- Replace static wire at the following locations

  New Freedom - Silver Lake (AE) - Cox"s Corner - Mount Laurel - Camden – Burlington (S0392.1).

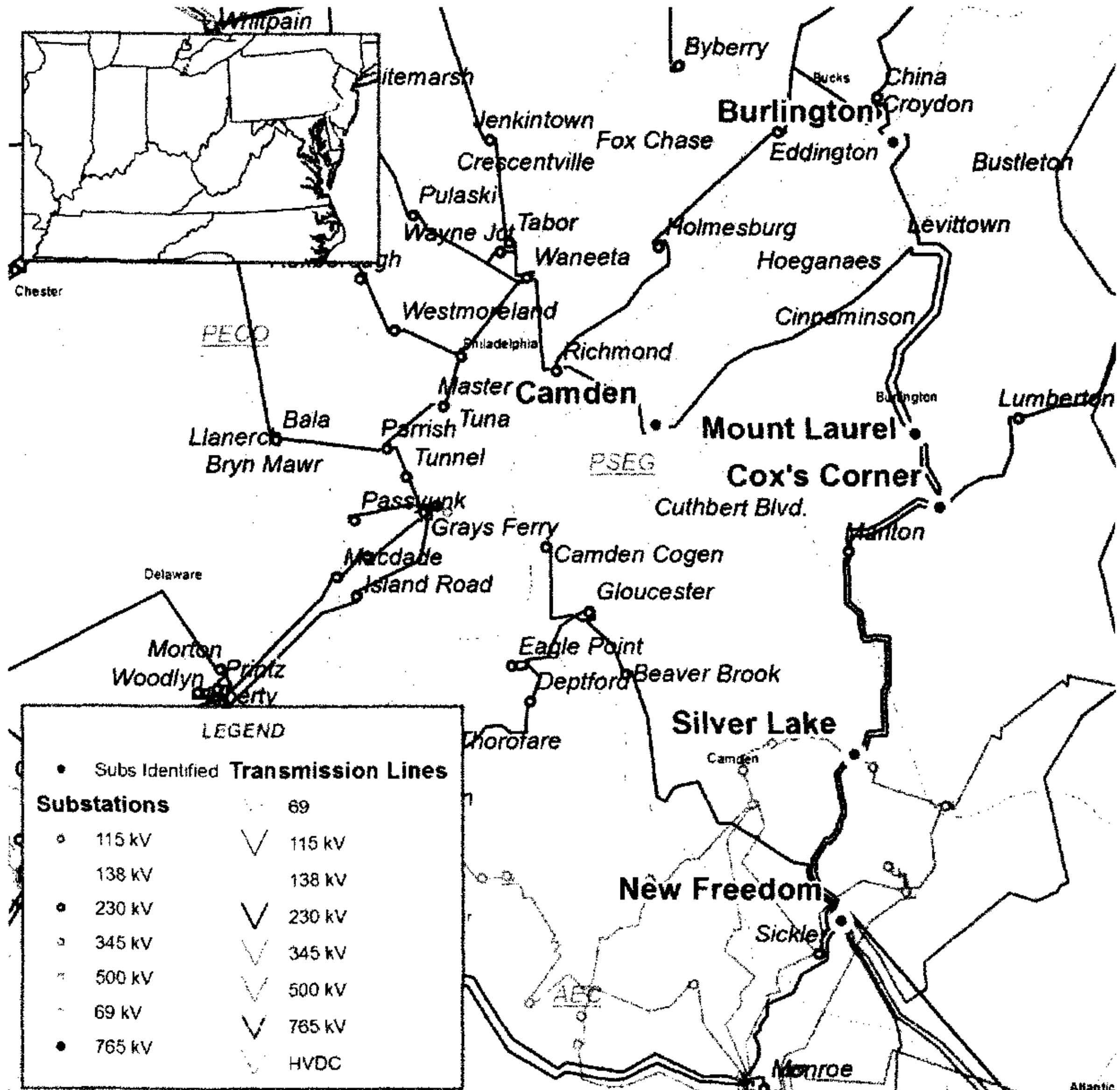
  New Freedom – Beaver Brook – Gloucester (S0392.2).
- Estimated Project Cost:

  $ 2.5 M

  $ 2.1 M
- Expected IS Date:

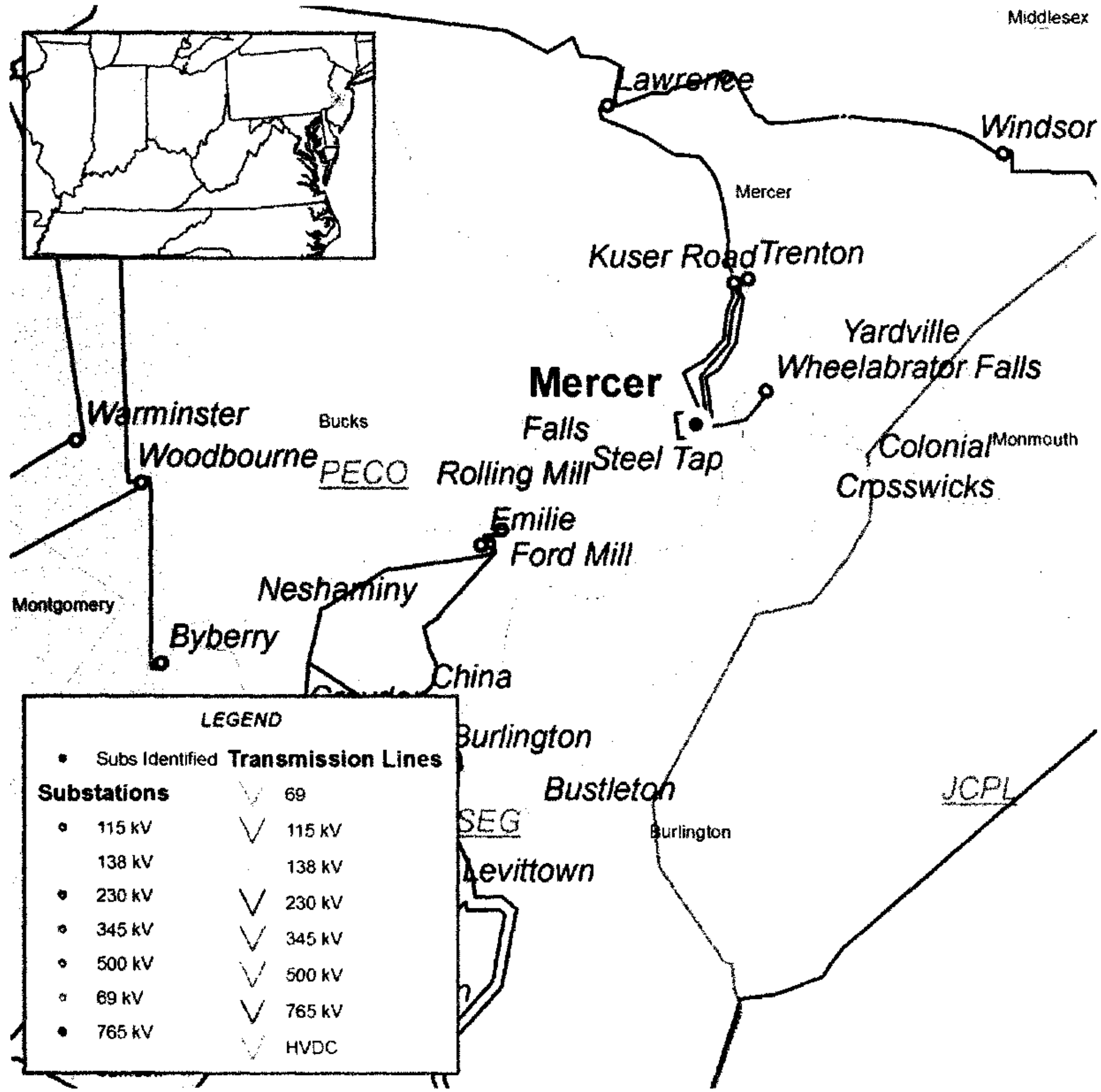
  6/1/2013

  6/1/2014



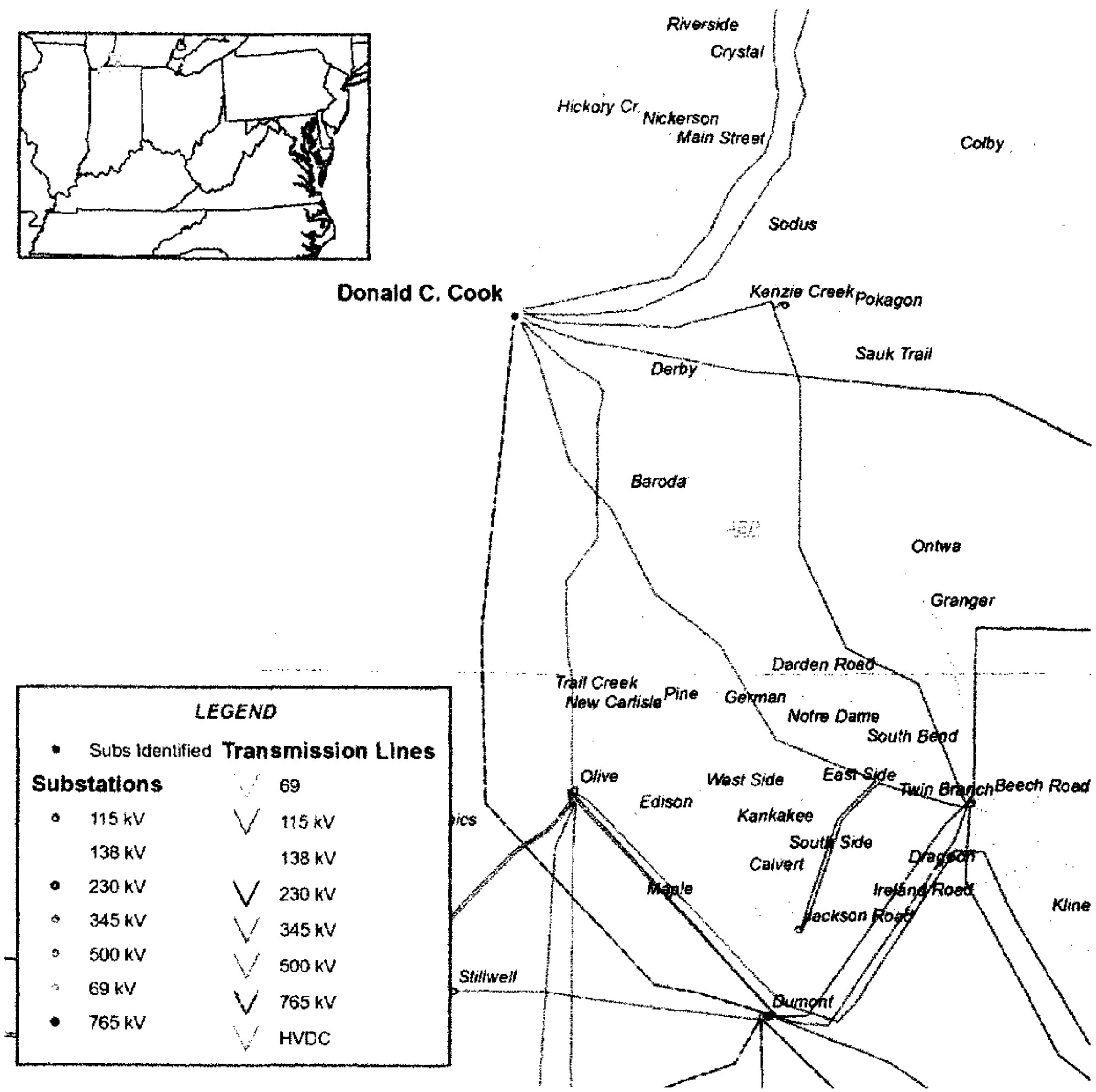
PSE&G Transmission Zone

- PSE&G Reliability:
- To improve reliability, productivity, accessibility and eliminate shared facility.
- Separate the transmission and generation by re-locating the Mercer Control House onto PSE&G property and replacing relays (S0393).
- Estimated Project Cost: $ 15 M
- Expected IS Date: 2013-2014



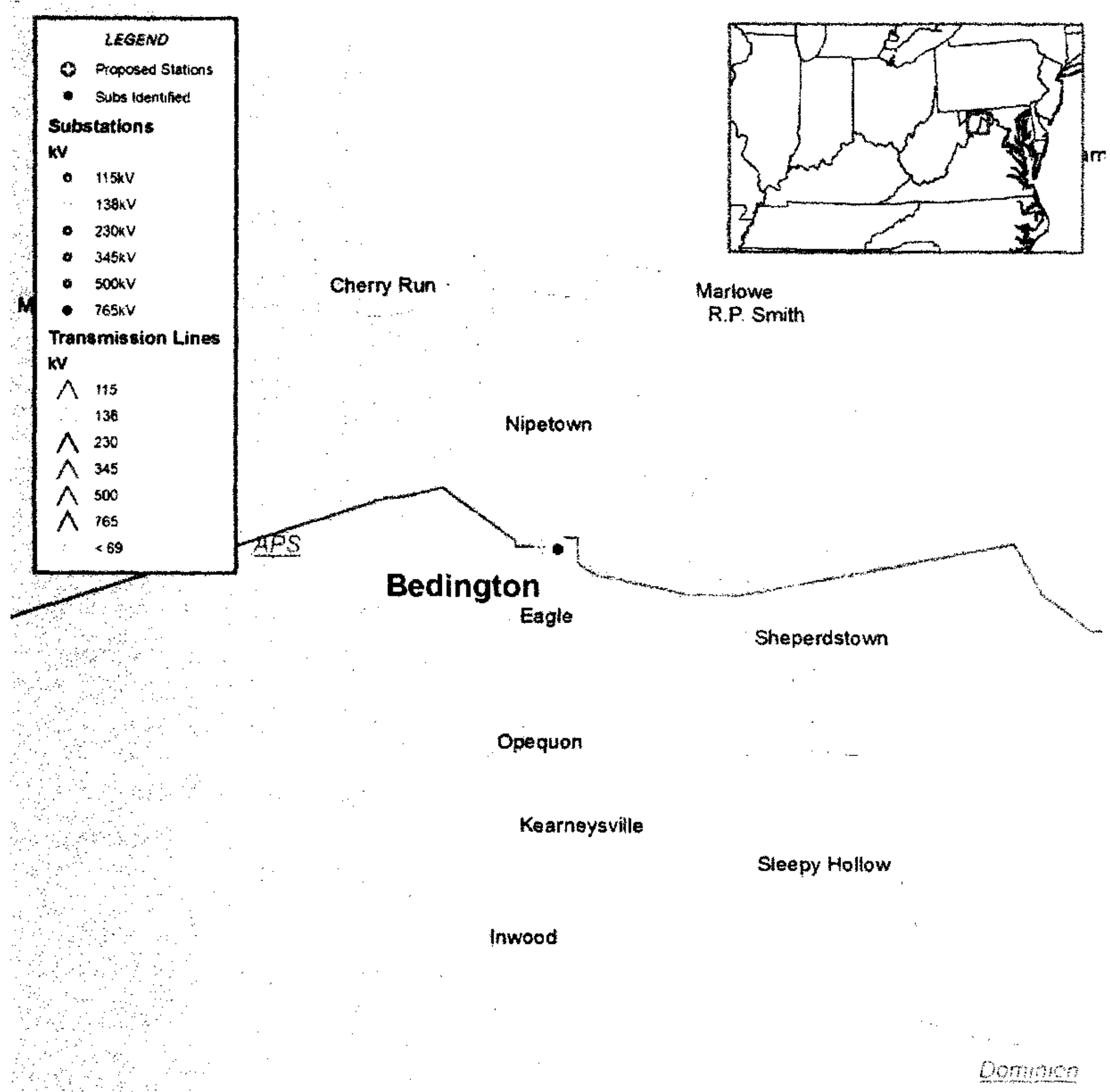
AEP Transmission Zone

- Supplemental Project
- Replace the Cook 765/345 kV transformer #4 and connect it in between CB K and K1. Establish a new 345 kV string O by installing two 345 kV breaker O and O1. Attach the Cook plant unit #1 in between O and O1. Install a CB J and J2 on the high side of the 345/34.5 kV transformer #5 and 5B respectively. Retire 345 kV CB L2. Retire 765 kV CB B2 and replace the 765 kV CB A2.(S0409)
- Estimated Project Cost: $37M
- Expected IS date: 1/1/2013



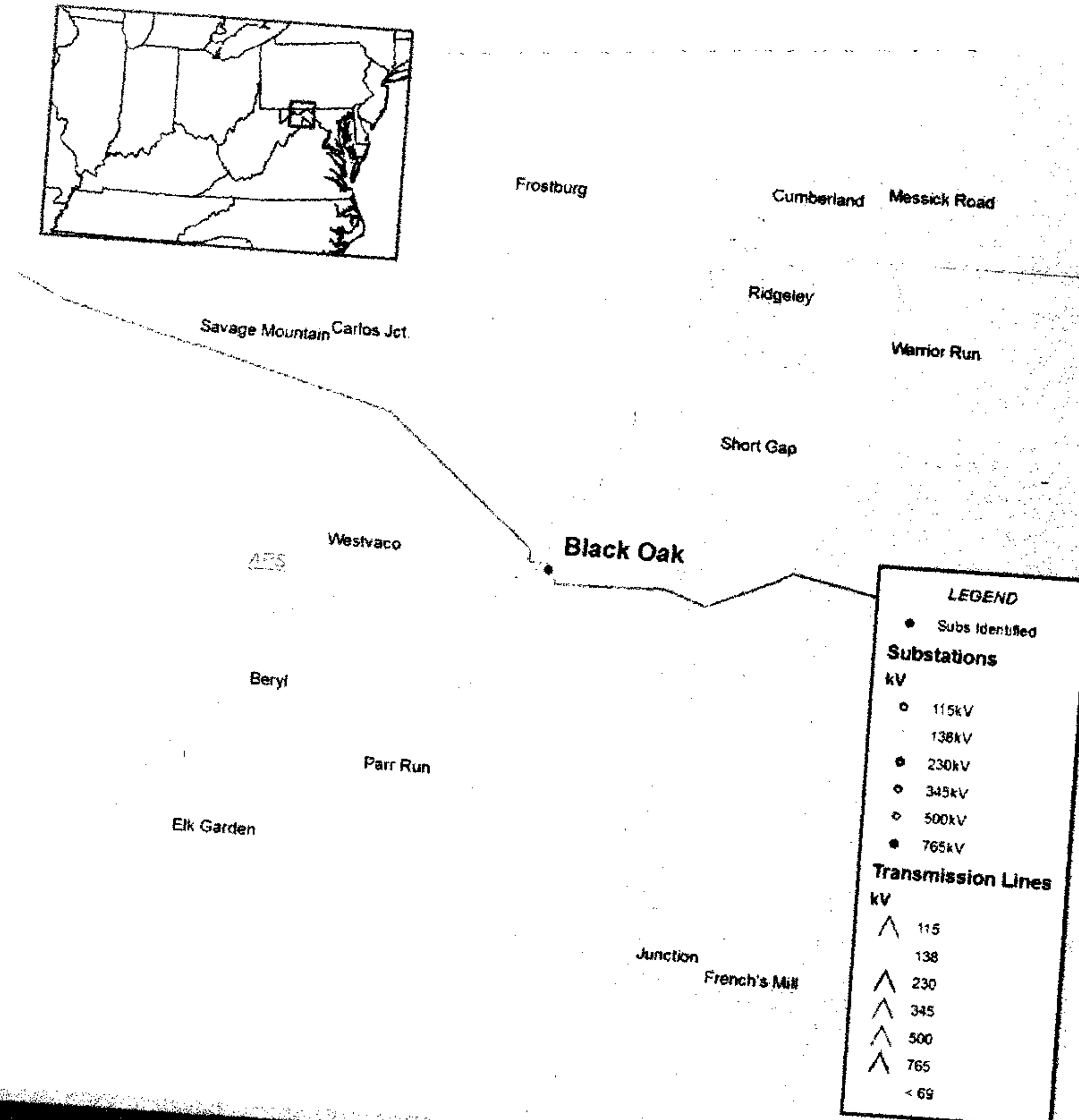
APS Transmission Zone

- Supplemental Project Withdrawal
- Cancel Project S0194: Replace the BDL-1, BDL-2 and BDL-3 500 kV breakers at Bedington
- Previous Expected IS date: 1/1/2013



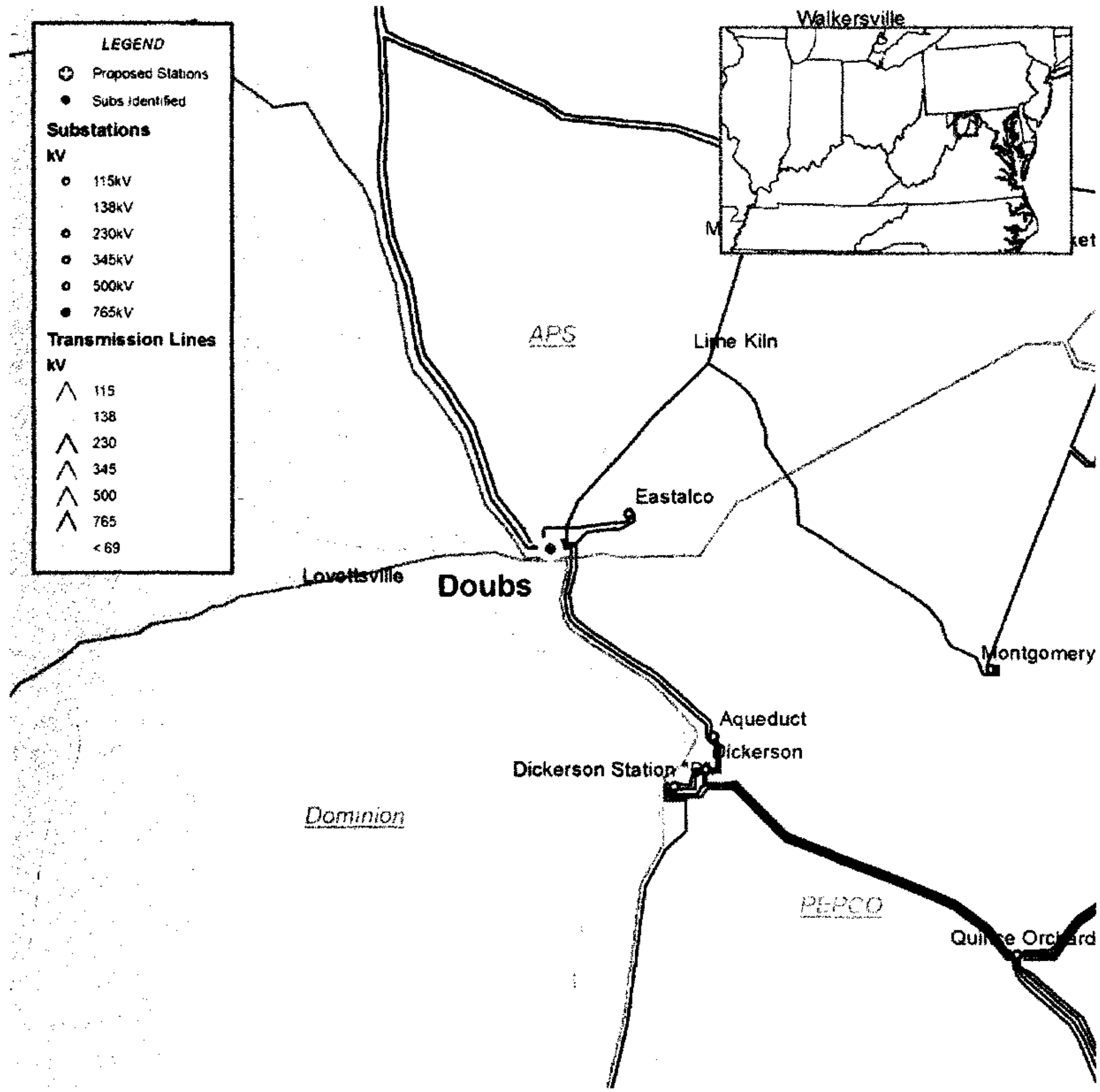
APS Transmission Zone

- Supplemental Project Withdrawal
- Cancel Project S0195: Replace the BOL-1, BOL-2 and BOL-3 500 kV breakers at Black Oak
- Previous Expected IS date: 1/1/2013



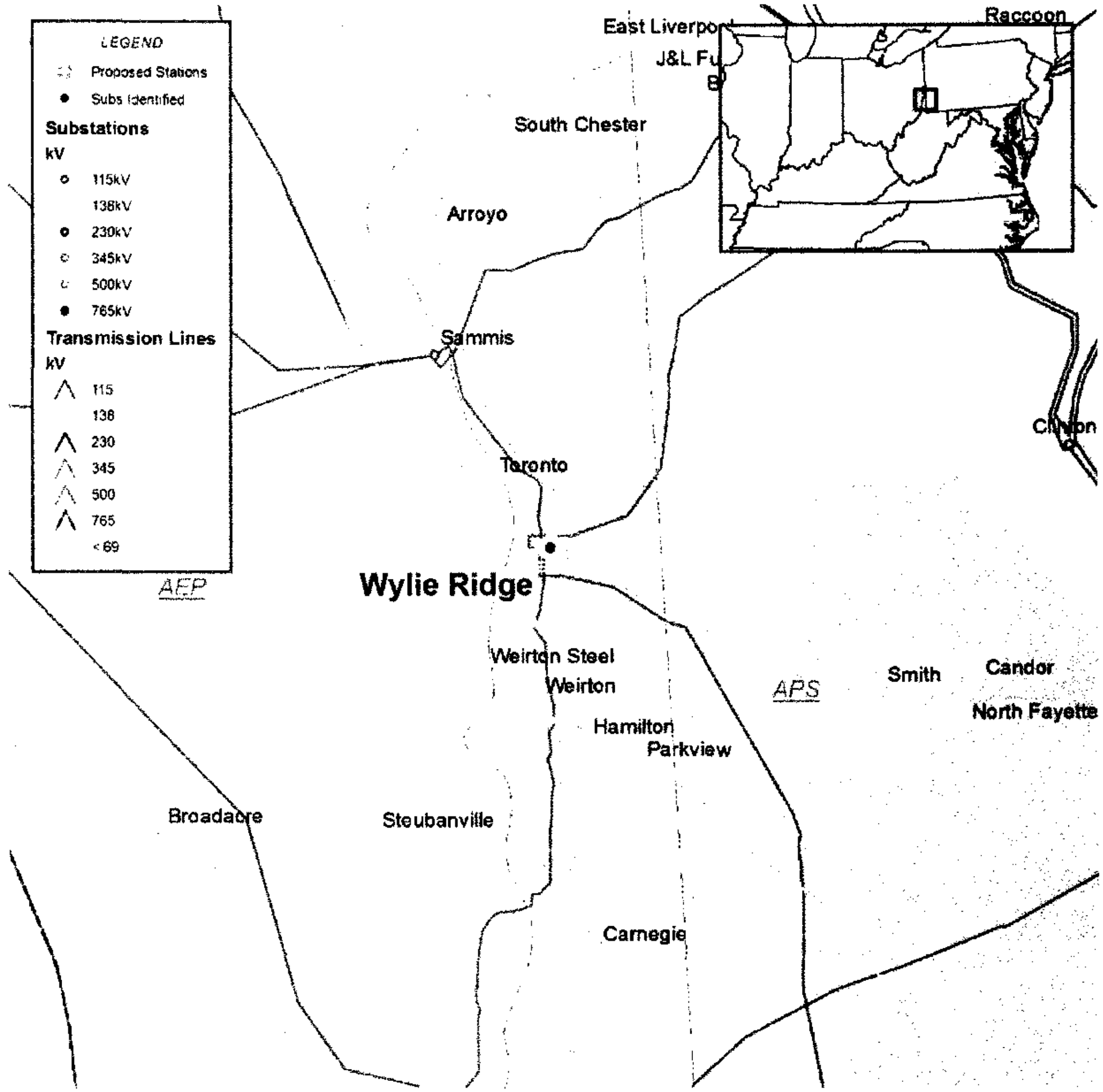
APS Transmission Zone

- Supplemental Project Withdrawal
- Cancel Project S0196: Replace the DL-50 500 kV breaker at Doubs
- Previous Expected IS date: 1/1/2013



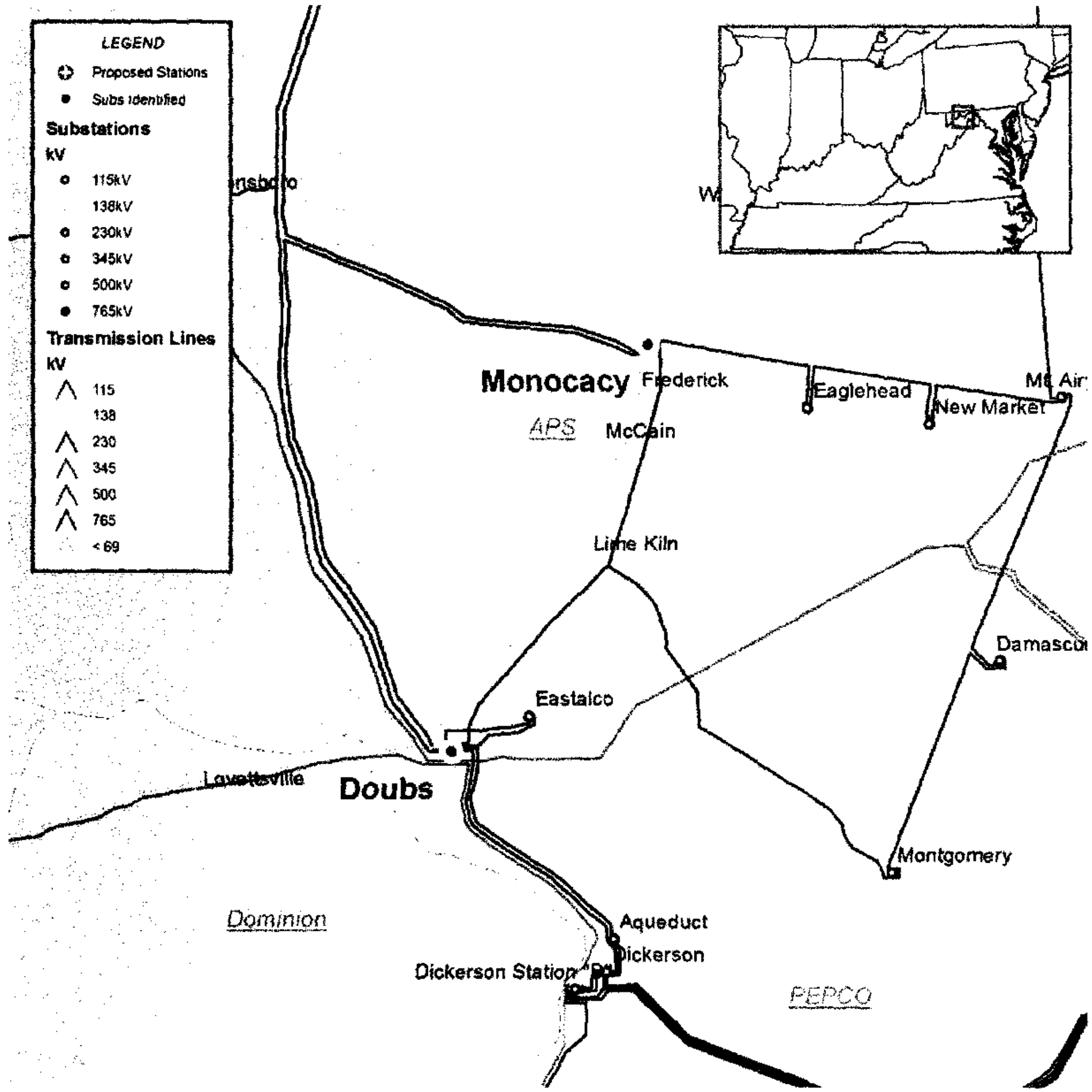
APS Transmission Zone

- Supplemental Project Withdrawal
- Cancel Project S0184: Replace the WK-1, WK-2, WK-3, WK-4, WK-5 and WK-6 345 kV breakers at Wylie Ridge
- Previous Expected IS date: 1/1/2013



APS Transmission Zone

- Supplemental Project Withdrawal
- Cancel Project S0202: Reconductor approximately 24.93 miles of Doubs - Monocacy 230kV with 1622 ACSS TW; upgrade terminal equipment at Doubs and Monocacy
- Previous Expected IS date: 1/1/2013



Questions?

Email: RTEP@pjm.com

OCC 16

Transmission Expansion Advisory Committee

February 16, 2012

Issues Tracking

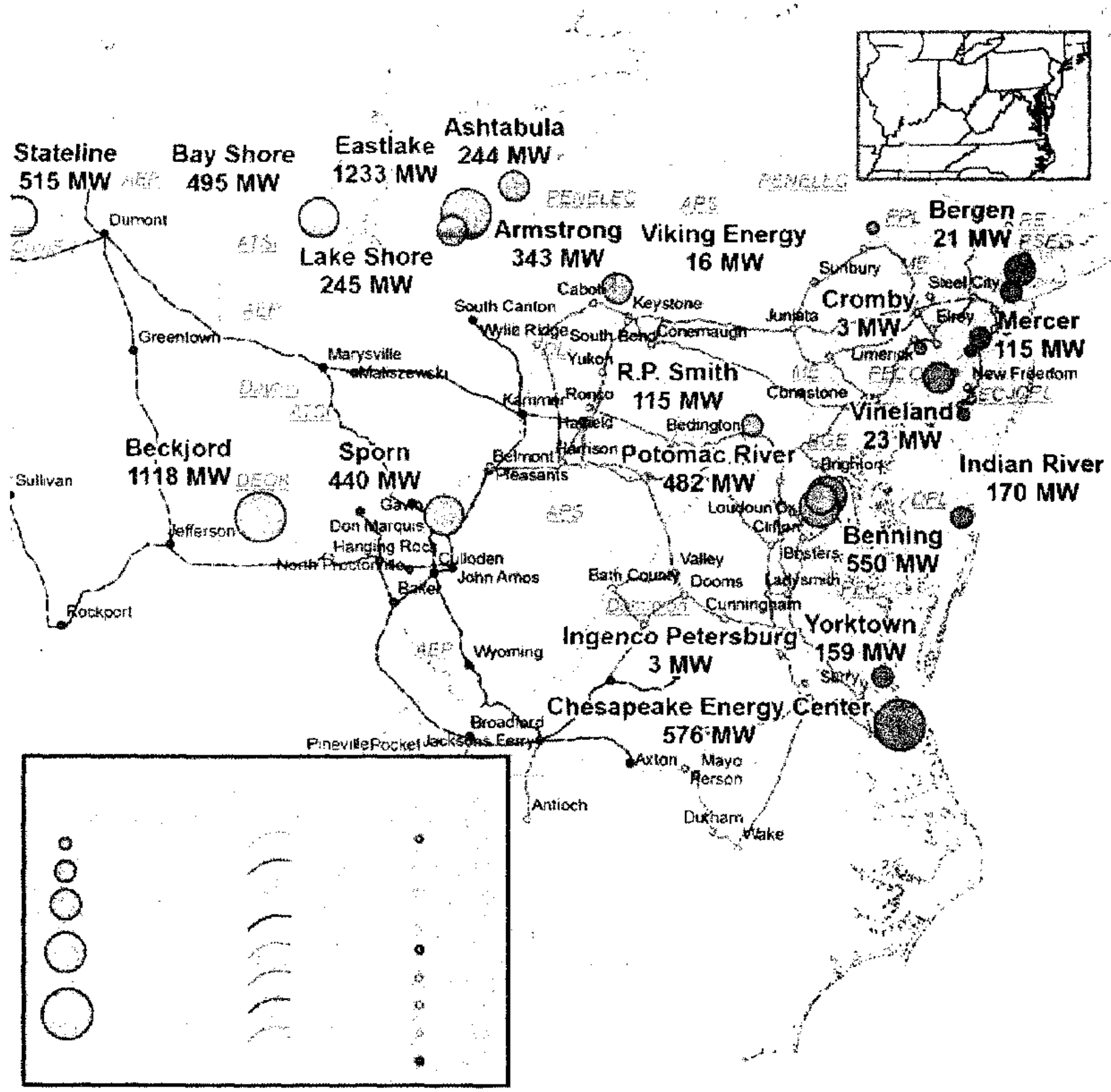
Issues Tracking

- Open Issues
  - None
- New Issues

Generation Retirements

Generation Retirement Notifications Since 11/2011

- Approximately 5400 MW's of notifications since November 2011
- Multiple Transmission Zones
- Potential Regional Impacts



Current Studies

Unit	Capacity	Trans Zone	Age (Years)	Official Owner Request	Requested Deactivation Date	Projected Deactivation Date	PJM Reliability Status
Chesapeake 1	111	DOM	58	11/15/2011	12/31/2014	12/31/2014	Reliability Analysis complete
Chesapeake 2	111	DOM	56	11/15/2011	12/31/2014	12/31/2014	Reliability Analysis complete
Chesapeake 3	147	DOM	52	11/15/2011	12/31/2015	12/31/2015	Reliability Analysis complete
Chesapeake 4	207	DOM	49	11/15/2011	12/31/2015	12/31/2015	Reliability Analysis complete
Yorktown 1	159	DOM	54	11/15/2011	12/31/2014	12/31/2014	Reliability Analysis complete
Bergen 3	21	PSEG	44	12/1/2011	6/1/2015	6/1/2015	Reliability Analysis complete
Burlington 8	21	PSEG	44	12/1/2011	6/1/2015	6/1/2015	Reliability Analysis complete

Current Studies

Unit	Capacity	Trans Zone	Age (Years)	Official Owner Request	Requested Deactivation Date	Projected Deactivation Date	PJM Reliability Status
National Park 1	21	PSEG	42	12/1/2011	6/1/2015	6/1/2015	Reliability Analysis Complete.
Mercer 3	115	PSEG	44	12/1/2011	6/1/2015	6/1/2015	Reliability Analysis Complete.
Sewaren 6	111	PSEG	46	12/1/2011	6/1/2015	6/1/2015	Reliability Analysis Complete.
Armstrong 1	172	AP		1/26/2012	9/1/2012	9/1/2012	Reliability Analysis Underway
Armstrong 2	171	AP		1/26/2012	9/1/2012	9/1/2012	Reliability Analysis Underway
Ashtabula 5	244	ATSI		1/26/2012	9/1/2012	9/1/2012	Reliability Analysis Underway
Bay Shore 2	138	ATSI		1/26/2012	9/1/2012	9/1/2012	Reliability Analysis Underway

Current Studies

Unit	Capacity	Trans Zone	Age (Years)	Official Owner Request	Requested Deactivation Date	Projected Deactivation Date	PJM Reliability Status
Bay Shore 3	142	ATSI		1/26/2012	9/1/2012	9/1/2012	Reliability Analysis Underway
Bay Shore 4	215	ATSI		1/26/2012	9/1/2012	9/1/2012	Reliability Analysis Underway
Eastlake 1	132	ATSI		1/26/2012	9/1/2012	9/1/2012	Reliability Analysis Underway
Eastlake 2	132	ATSI		1/26/2012	9/1/2012	9/1/2012	Reliability Analysis Underway
Eastlake 3	132	ATSI		1/26/2012	9/1/2012	9/1/2012	Reliability Analysis Underway
Eastlake 4	240	ATSI		1/26/2012	9/1/2012	9/1/2012	Reliability Analysis Underway
Eastlake 5	597	ATSI		1/26/2012	9/1/2012	9/1/2012	Reliability Analysis Underway
Lake Shore 18	245	ATSI		1/26/2012	9/1/2012	9/1/2012	Reliability Analysis Underway

Current Studies

Unit	Capacity	Trans Zone	Age (Years)	Official Owner Request	Requested Deactivation Date	Projected Deactivation Date	PJM Reliability Status
R Paul Smith 3	28	AP		1/26/2012	9/1/2012	9/1/2012	Reliability Analysis Underway
R Paul Smith 4	87	AP		1/26/2012	9/1/2012	9/1/2012	Reliability Analysis Underway
Walter C Beckjord 1	94	DEOK		2/1/2012	5/1/2012	5/1/2012	Reliability Analysis Underway
Walter C Beckjord 2	94	DEOK		2/1/2012	5/1/2012	5/1/2012	Reliability Analysis Underway
Walter C Beckjord 3	128	DEOK		2/1/2012	5/1/2012	5/1/2012	Reliability Analysis Underway
Walter C Beckjord 4	150	DEOK		2/1/2012	4/1/2015	4/1/2015	Reliability Analysis Underway
Walter C Beckjord 5	238	DEOK		2/1/2012	4/1/2015	4/1/2015	Reliability Analysis Underway
Walter C Beckjord 6	414	DEOK		2/1/2012	4/1/2015	4/1/2015	Reliability Analysis Underway

Current analysis

- Initial analysis completed and awaiting Generation Owner response
  - Dominion Transmission Zone
  - PSEG Transmission Zone
  - Allegheny Power Transmission Zone
  - ATSI Transmission Zone
  - DEOK Transmission Zone
- Initial analysis identified the need for transmission upgrades
- Upgrades include existing baseline projects as well as new upgrades
  - New EHV being considered to address issues in the Dominion Transmission Zone
- Stakeholder Input

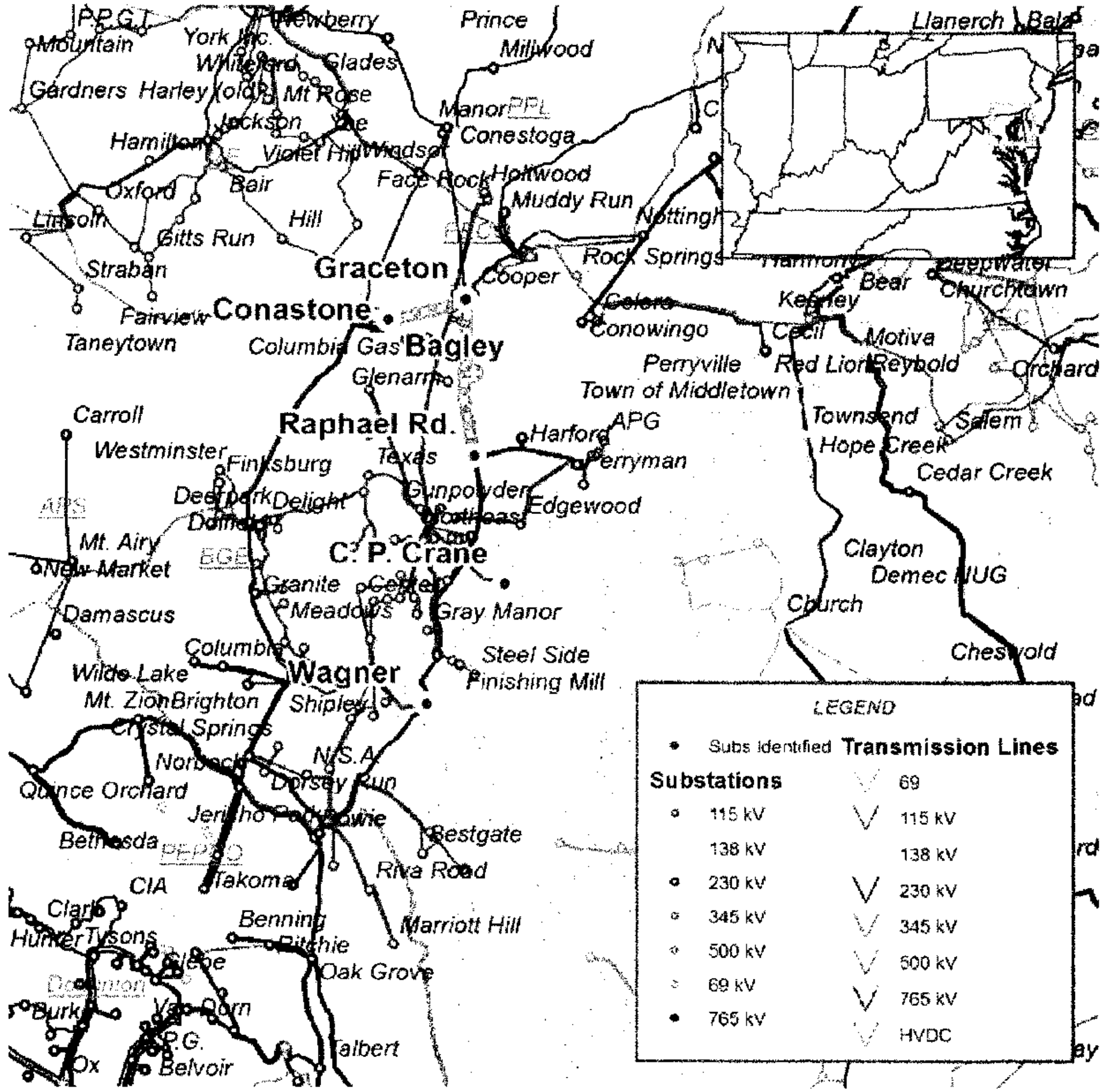
Conastone – Graceton – Bagley – Raphael Road Second 230 kV Circuit & Crane and Wagner Retirement Sensitivity Study

Conastone – Graceton – Bagley – Raphael Road

- Prevailing flow is north to south from Conastone – Graceton – Bagley – Raphael Road 230 kV
- Current approved RTEP Upgrades
  - Second Conastone – Graceton – Bagley – Raphael Road 230 kV circuit
- Crane and Wagner Retirement Study Sensitivity

Crane and Wagner Retirement Sensitivity Study

- Crane 399 MW
- Wagner 998 MW
- Both reduce flow on Conastone – Graceton – Bagley - Raphael Road



Wagner and Crane generators retirement Result

- PJM performed the potential retirement study of the Wagner (998 MW) and Crane (399 MW) generators in BGE territory.
- The latest 2016 RTEP basecase was used.
- Analysis performed:
  - Baseline N-1 thermal and voltage
  - Generation deliverability
  - Load deliverability for MAAC, SWMAAC, BGE and PEPCO LDAs
  - N-1-1 voltage for the 500 kV contingencies

- Violations identified:
  - Baseline → Seven thermal and several voltage
  - Generation deliverability → 21 thermal
  - Load deliverability → Three thermal and a few voltage
  - N-1-1 → Several voltage collapse

- Remaining studies:
  - N-1-1 for below 500 kV contingencies
  - BGE *local* criteria study

Wagner and Crane generators retirement Result

- **<u>Potential System Upgrades to mitigate the identified violations</u>**:
  - Build Emory Grove 500/230 kV substation ($82.5 M)
    - Existing PJM baseline upgrade # b1254
  - Build a parallel Conastone –Graceton – Bagley – Raphael Rd 230 kV circuit ($121 M)
    - Existing PJM baseline upgrade # b0497, b1016, b1251
  - Install 500 MVAR SVC at Brighton 500 kV substation ($60 M)
  - Install 200 MVAR capacitor at Hunterstown 500 kV substation ($4 M)
  - Replace Conemaugh 500/230 kV transformer ($16 M)
  - Rebuild Shade Gap – Roxbury 115 kV circuit ($8 M)
  - Rebuild the Howard – Pumphrey 230 kV circuit ($12 M)
  - Install a third Wagner 230/115 transformer ($25 M)
  - Remove terminal limitation on Pumphrey 230/115 kV transformer ($0.1 M)

Crane & Wagner Retirement Sensitivity Study

- Recommendation
  - Continue to evaluate the timing of existing baseline upgrades as a result of the Crane and Wagner retirement study
  - Perform additional sensitivity analysis

2012 RTEP
Scenario and Sensitivity Analyses

Previous RPS Studies

- Reliability Studies
  - 4 GW Offshore
  - 10 GW Offshore
  - 20 GW Offshore
- Market Efficiency Studies (SCOPF)
  - 4 GW Offshore
  - 20 GW Offshore
- Transmission Overlays

2012 RTEP Scenario Analyses – Define Proposed Scenarios

- The following scenario analysis will be performed as part of the 2012 RTEP
  - Renewable Portfolio Standards (RPS) Scenarios
    - 0 GW offshore
      - Perform reliability analysis
    - 10 GW offshore
      - Reliability analysis performed in 2011 RTEP
      - Perform SCOPF and develop transmission overlay by using both reliability and market efficiency analysis
    - Sensitivity of sourcing a portion of RPS from neighboring entities
      - Perform reliability analysis
  - High load growth Scenario
  - At-risk generation Scenario
    - RPM
    - Regulatory

2012 RTEP Scenario Analyses - RPS

- 2012 RTEP RPS Scenario Sourcing Strategy
  - 10 GW Offshore (discussed last year but was not completed due to resource limitations)
  - O GW Offshore
  - 40% External Resource Strategy
    - Utilize same source distribution within PJM for 60% of the total renewables required
    - Assume HVDC injections into PJM for 40% of the resources
      - Utilize wind profiles for resources further west of PJM

2012 RTEP Scenario Analyses – High Load Growth

- Develop a high growth load forecast based on a more optimistic economic projection
- Update the 2017 RTEP base case with a high growth load forecast
- Perform reliability analyses using the updated base cases
  - Generation Deliverability
  - Load Deliverability (with initial focus on historically constrained areas)
  - 15 year analyses

2012 RTEP Scenario Analyses – “At-Risk” Generation

- 2012 RTEP “AT-Risk” scenario analyses will build on the work completed in 2011
- Utilize “Coal Capacity at Risk for Retirement in PJM” report
  - http://pjm.com/documents/~/media/documents/reports/20110826-coal-capacity-at-risk-for-retirement.ashx
- Perform reliability analysis on potential impact

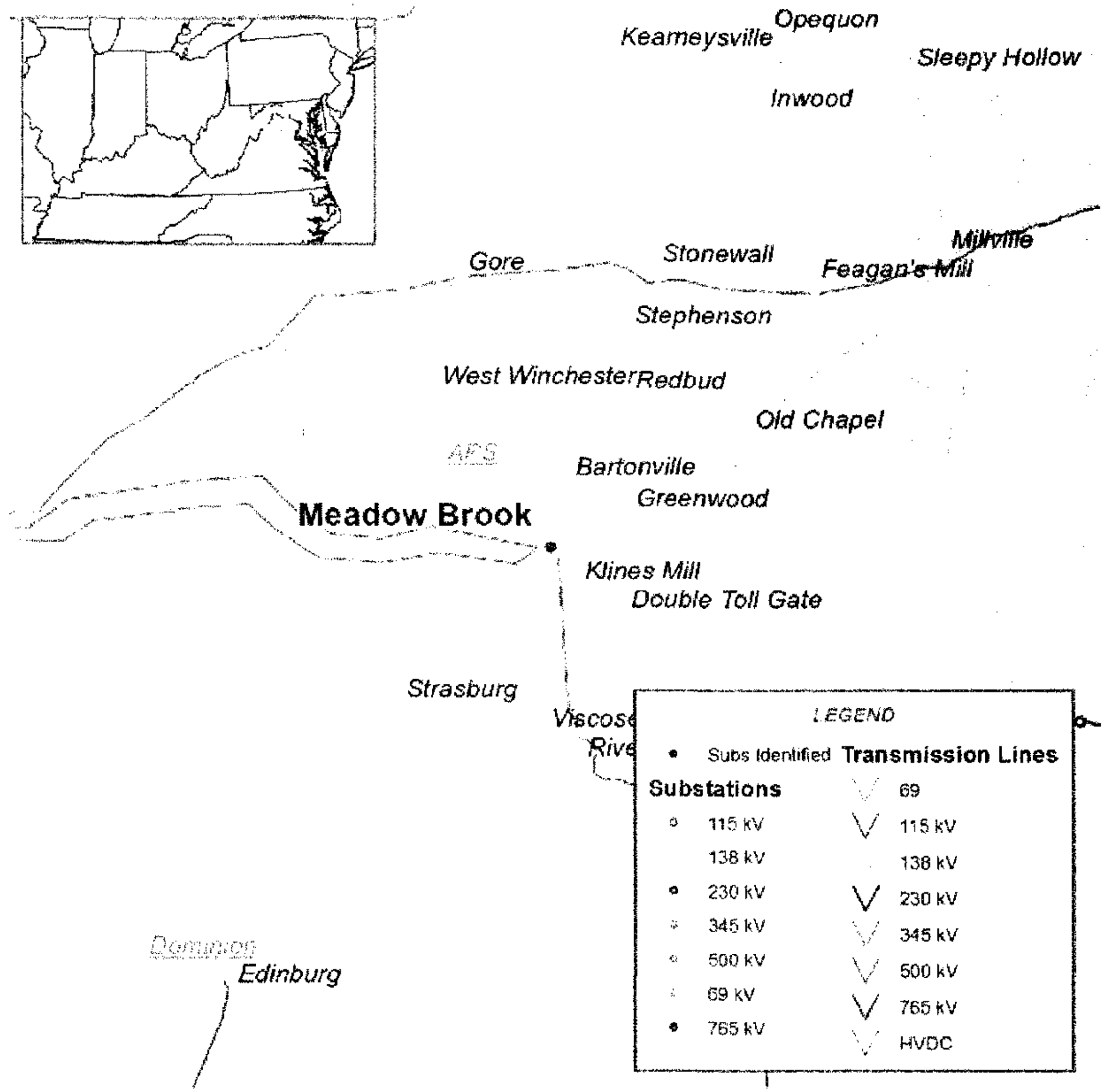
2012 RTEP Scenario Analyses – “At-Risk” Generation

- Reliability Analysis Scope
  - Load Deliverability analysis of select LDAs
    - MAAC
    - EMAAC
    - SWMAAC
    - Others
  - Area CETO will be increased based on the amount of “at-risk” generation located within the area
  - Additional analyses will be done focusing on potential regional issues

Short Circuit

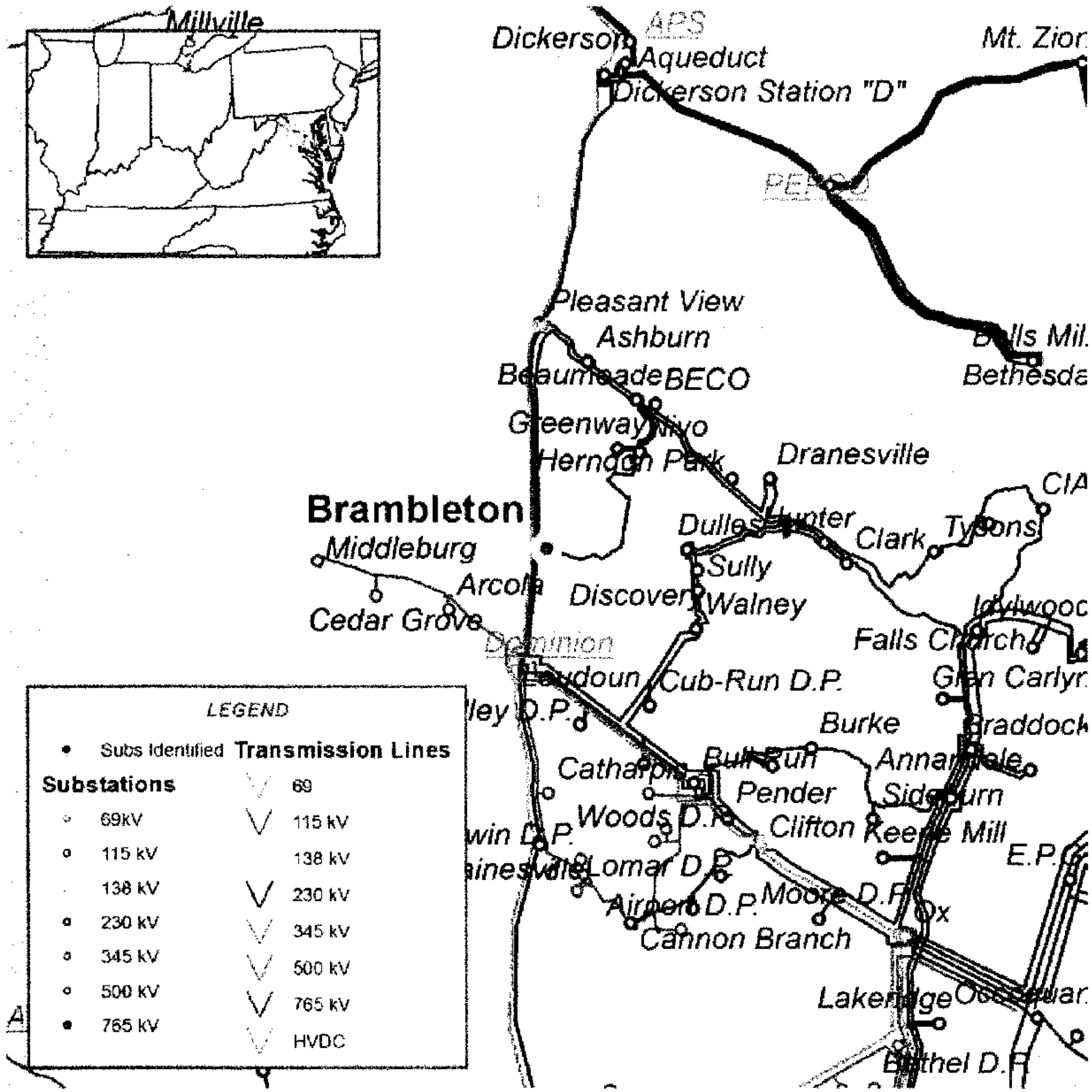
APS Transmission Zone

- The Meadow Brook 138 kV breakers 'MD-1' and 'MD-2' are overstressed
- Proposed Solution: Replace Meadow Brook 138kV breakers 'MD-1' and 'MD-2' (b0347.33, b0347.34)
- Estimated Project Cost: $190 K per breaker
- Project IS Date: 6/1/2013



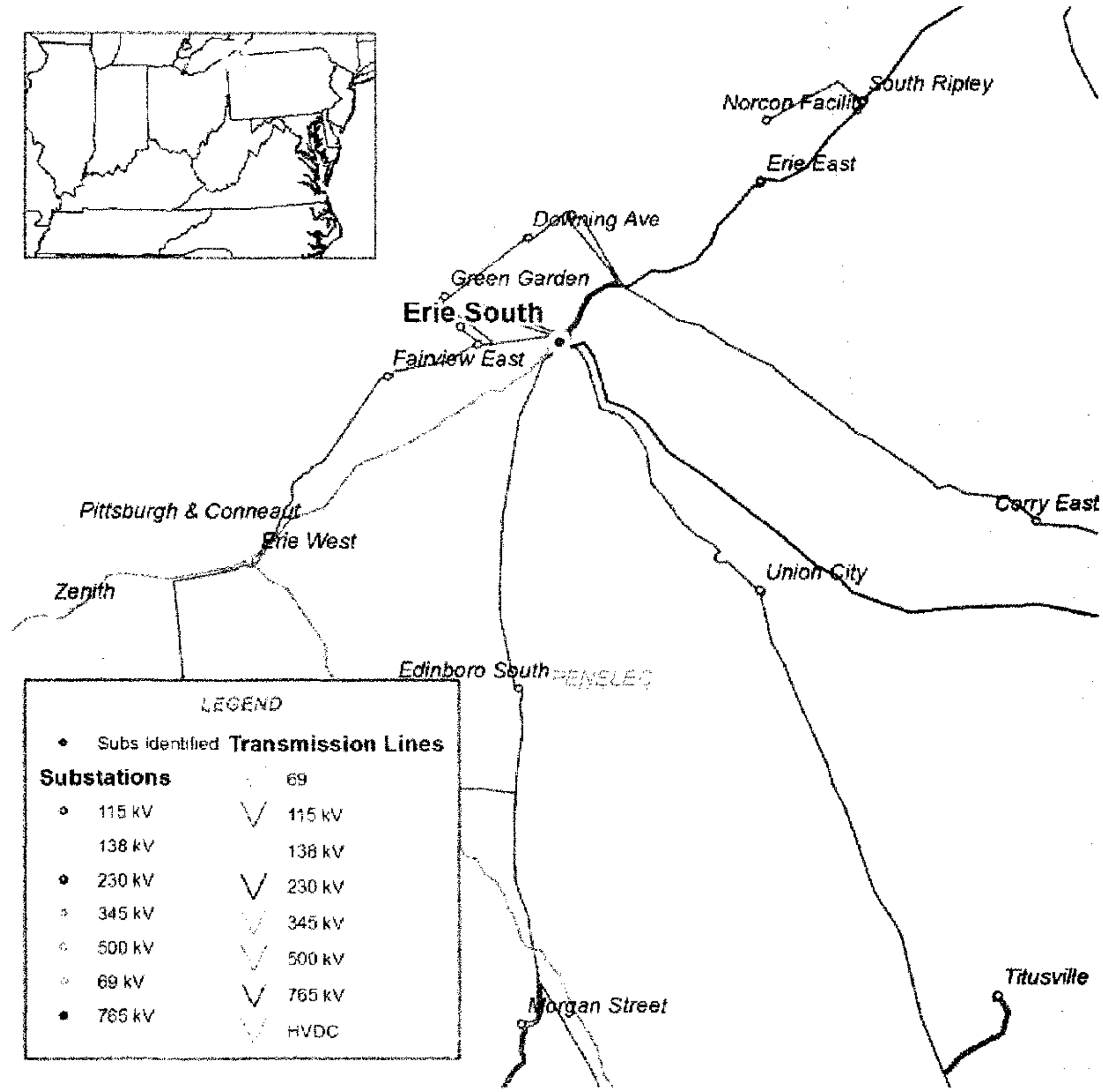
Dominion Transmission Zone

- The Brambleton 230 kV breaker ‘2094T2095’ is overstressed
- Proposed Solution: Replace Brambleton 230 kV breaker ‘2094T2095’ (b1698.6)
- Estimated Project Cost: $220 K per breaker
- Expected IS Date: 6/1/2016



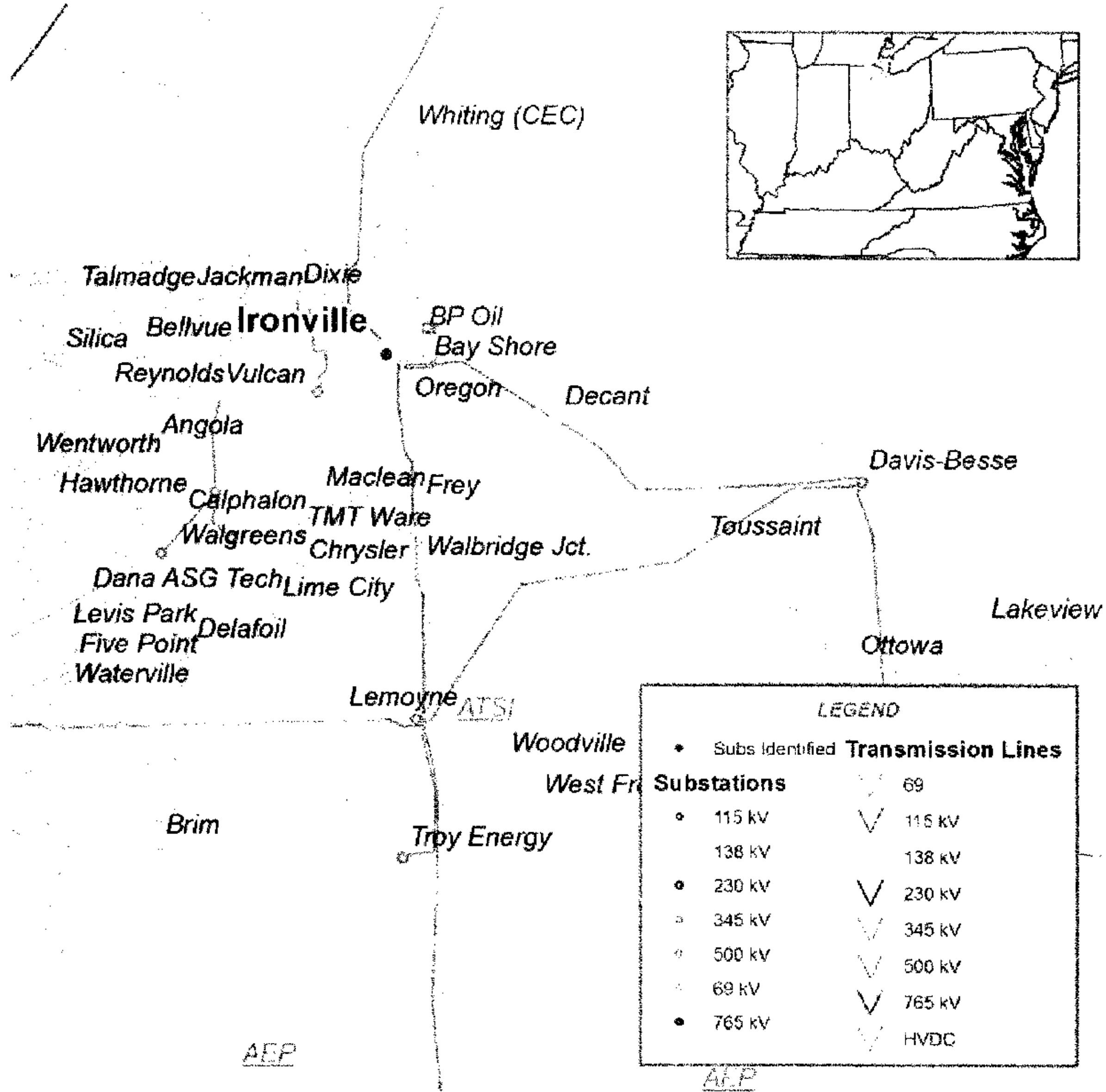
PENELEC Transmission Zone

- The Erie South 115 kV breaker 'Union City' is overstressed
- Proposed Solution: Replace the Erie South 115 kV breaker 'Union City' (b1821)
- Estimated Project Cost: $150 K
- Expected IS Date: 6/1/2016



ATSI Transmission Zone

- The Ironville 138 kV breaker '33-B-13208' is overstressed
- Proposed Solution: Replace the Ironville 138 kV breaker '33-B-13208' (b1820)
- Estimated Project Cost: $180 K
- Expected IS Date: 6/1/2016



Questions?

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