VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

The undersigned, Adam Long, VP Gas Pipeline Operations, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained are true and correct to the best of his knowledge, information, and belief.

Adam Long

Adam Long Affiant

Subscribed and sworn to before me by Adam Long on this 29 day of November 2021.

SHANNON L. WALL
Notary Public, North Carolina
Mecklenburg County
My Commission Expires
June 28, 2022

Shannon L. Wall

NOTARY PUBLIC

My Commission Expires: 6/28/2022

VERIFICATION

STATE OF NORTH CAROLINA	)	
	)	**SS:**
COUNTY OF MECKLENBURG	)	

The undersigned, Brian Weisker, SVP, Chief Op Off Natural Gas, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained are true and correct to the best of his knowledge, information, and belief.

B. R. Wei

Brian Weisker Affiant

Subscribed and sworn to before me by Brian Weisker on this 29th day of November, 2021.

SHANNON L. WALL
Notary Public, North Carolina
Mecklenburg County
My Commission Expires
June 28, 2022

Shannon L. Wall

NOTARY PUBLIC

My Commission Expires: 6/28/2022

VERIFICATION

STATE OF NORTH CAROLINA	)	
	)	**SS:**
COUNTY OF MECKLENBURG	)	

The undersigned, Bryan Manges, Director Gas Utility & Infrastructure, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Bryan Manges Affiant

Subscribed and sworn to before me by Bryan Manges on this 22nd day of November, 2021.

NOTARY PUBLIC

Tracy R Landrum
NOTARY PUBLIC
MECKLENBURG COUNTY, N.C.
My Commission Expires 05-07-2023

My Commission Expires: 05/07/2023

VERIFICATION

STATE OF NORTH CAROLINA)
) SS:
COUNTY OF MECKLENBURG)

The undersigned, David Raiford, Manager Accounting I, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information, and belief.

David Raiford
David Raiford Affiant

Subscribed and sworn to before me by David Raiford on this 29 day of November, 2021.

JENNIFER R. WEHBIE NOTARY PUBLIC MECKLENBURG COUNTY, NC

NOTARY PUBLIC

My Commission Expires: November 18, 2025

VERIFICATION

STATE OF OHIO)
) **SS:**
COUNTY OF HAMILTON)

The undersigned, Sarah E. Lawler, VP Rates & Regulatory Strategy OH/KY, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of her knowledge, information and belief.

Sarah E. Lawler Affiant

Subscribed and sworn to before me by Sarah E. Lawler on this 1st day of December, 2021.

NOTARY PUBLIC

My Commission Expires:

NOTARIAL SEAL STATE OF OHIO

ROCCO O. D'ASCENZO
ATTORNEY AT LAW
Notary Public, State of Ohio
My Commission Has No Expiration
Section 147.03 R.C.

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

The undersigned, Sarah Stabley, Managing Director, Gas Supply Optimization & Pipeline Services, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information, and belief.

Sarah Stabley Affiant

Subscribed and sworn to before me by Sarah Stabley on this 23 day of November, 2021.

NOTARY PUBLIC

My Commission Expires: March 1, 2025

JANET P CURETON
NOTARY PUBLIC
Mecklenburg County
State of North Carolina

KyPSC Case No. 2021-00405
TABLE OF CONTENTS

Duke Energy Kentucky
Case No. 2021-00405
STAFF First Set Data Requests
Date Received: November 19, 2021

STAFF-DR-01-001

REQUEST:

Refer to the Application, paragraph 4.

a. Provide the original net book value and estimated useful life, remaining useful life, and depreciation schedules of the man-made cavern in Erlanger, Kentucky (Erlanger Cavern), along with related propane-air facilities.

b. Elaborate on the "nature of construction" that prevents the Erlanger Cavern from being inspected or repaired.

c. State whether Duke Kentucky monitors the Erlanger Cavern to ensure its safe and reliable operation. If so, describe how Duke Kentucky conducts such monitoring.

d. State whether Duke Kentucky has conducted any study or analysis regarding the Erlanger Cavern's remaining useful life. If so, provide any such study or analysis.

e. State whether Duke Kentucky is aware of any specific safety concerns, defects, or inoperable conditions associated with the Erlanger Cavern. If so, describe these conditions or concerns.

f. State whether Duke Kentucky is aware of any instance where the Erlanger Cavern failed to provide needed supply or pressure to its system, failed to operate during a peak day, caused firm customer curtailments or interruptions, or resulted in service outages. If so, describe these failures and the impact on Duke Kentucky's system.

g. Provide support for Duke Kentucky's statement that, "Similar propane caverns of a similar vintage have failed, resulting in the need to immediately retire such facilities." Include in this response a description of the similarities of the failed facilities and the Erlanger Cavern.

RESPONSE:

a. Please see STAFF-DR-01-001(a) Attachment for requested information. Note these values are the amounts on Duke Energy Kentucky's books. As discussed in the Company's application, 64% is allocated to Duke Energy Ohio and that portion would not be included in the Duke Energy Kentucky regulatory asset request.

b. The Erlanger cavern is hundreds of feet underground and is inaccessible for inspection or repair.

c. Erlanger Cavern pressure is continuously monitored to ensure safe and reliable operation. Duke Energy's Gas Control has low and high pressure alarm set points for the cavern which would prompt the gas controller to take action if necessary.

d. Duke Energy Kentucky and Duke Energy Ohio commissioned an analysis with Lummus Consultants International that was published on February 24th, 2015 recommending decommissioning of the propane air facilities and storage caverns. Please see STAFF-DR-01-001(d) Attachment.

e. While no specific safety concerns or defects are known for the Erlanger Cavern, the 2015 Lummus Consultants International analysis describes the specific risks associated with continued operation of this cavern.

f. Duke Energy Kentucky is unaware of an instance where the Erlanger Cavern failed to provide needed supply or pressure to its system, failed to operate during a peak day, caused firm customer curtailments or interruptions, or resulted in service outages. The retirement is recommended so to avoid such risks as the cavern is now sixty-years old.

g. Late in 2012, Enterprise Products Todhunter Propane Cavern failed, resulting in the release of propane to groundwater and the surrounding environment. The Todhunter Propane Cavern was constructed and placed in service in 1959 by Cincinnati Gas & Electric (predecessor company to Duke Energy Ohio), 2 years prior to placing the Erlanger Cavern in service in 1961. The Erlanger propane cavern is of a similar vintage and design to that of the Todhunter Cavern.

PERSON RESPONSIBLE: David Raiford – a.
Brian Weisker – b-g.

FERC Account	Useful Life Per Most Recent Depreciation Study (Years)	As of September 30, 2021			Accrual Depreciation Rate (Annual)			Estimated Annual Depreciation Expense		
		Original Book Cost	Allocated Reserve	Net Book Value	Life	Cost of Removal	Total	Life	Cost of Removal	Total
1900	40	$ 5,186	$ 2,886	$ 2,300	1.95%	0.19%	2.14%	$ 101	$ 10	$ 111
2040	Perpetual	117,711	-	117,711						
2041	50	24,439	23,667	772	0.02%	0.00%	0.02%	5	-	5
2050	55	4,658,274	1,976,342	2,681,932	4.27%	0.43%	4.70%	198,908	20,031	218,939
2110	55	6,964,411	4,261,862	2,702,549	7.97%	0.89%	8.86%	555,064	61,983	617,047
2762	65	4,419	756	3,663	1.34%	0.30%	1.64%	59	13	72
2780	52	8,305	516	7,789	1.58%	0.46%	2.04%	131	38	169
2940	25	32,004	32,004	-	4.70%	0.00%	4.70%	1,504	-	1,504
3620	48	32,250	522	31,728	2.00%	0.35%	2.35%	645	113	758
		$ 11,846,999	$ 6,298,555	$ 5,548,444				$ 756,417	$ 82,188	$ 838,605
					Number of years until fully depreciated			7.3		6.6

Gas System Master Plan Study 2015-2035

Prepared for

Duke Energy Corporation

February 24, 2015

Lummus Consultants International

A World of Solutions™

Disclaimer Notice

This document was prepared by Lummus Consultants International, Inc. ("Consultant") for the benefit of Duke Energy Corporation ("Company"). With regard to any use or reliance on this document by any party other than Company, Consultant, its parent, and affiliates: (a) make no warranty, express or implied, with respect to the use of any information or methodology disclosed in this document; and (b) specifically disclaims any liability with respect to any reliance on or use of any information or methodology disclosed in this document.

Any recipient of this document, other than Company, by their acceptance or use of this document, releases Consultant, its parent, and affiliates from any liability for direct, indirect, consequential, or special loss or damage whether arising in contract, warranty, express or implied, tort or otherwise, and irrespective of fault, negligence, and strict liability of Consultant. This document was prepared based on information provided by Company and the quality of the work product of Consultant is therefore contingent upon the accuracy, correctness, completeness and fitness for purpose of the information provided by Company. Consultant makes no assurances, representations or warranty, express or implied, as to, or assumes any responsibility for the accuracy, correctness, completeness or fitness for purpose of any information provided by Company.

ABOUT LUMMUS CONSULTANTS

Lummus Consultants International, Inc. (Lummus Consultants), through its legacy companies, including Stone & Webster Management Consultants, Inc. and Shaw Consultants International, Inc., has a history of over 100 years of providing engineering, construction, and consulting services to the energy industry. Stone & Webster Management Consultants was part of Stone & Webster, Inc., a preeminent engineering and construction firm established in 1889 that specialized in the energy industry. Stone and Webster, Inc. was purchased by The Shaw Group in 2000, and subsequently Stone & Webster Management Consultants, Inc. was renamed Shaw Consultants International, Inc. In February 2013, the Shaw Group was acquired by Chicago Bridge & Iron Company N.V. (CB&I) (NYSE: CBI). The combination of CB&I and The Shaw Group under the CB&I brand creates one of the world's largest engineering, construction, and consulting companies focused on the global energy industry. Shaw Consultants has become Lummus Consultants International, Inc., an independent company in CB&I's Lummus Technology operating group.

Lummus Consultants provides technical advisory and due diligence services to investment firms, project developers, and plant owners in the gas delivery, process, power, petrochemical, and refining industries. Our services include:

- Transmission Interconnection and Expansion Plans
- Capital and O&M Expenditures Assessments
- Project Identification and Development
- Technology Assessment and Project Feasibility
- Remaining Life Evaluations
- Independent Lenders' Engineer / Technical Review
- Condition Assessment and Replacement Programs Review
- Owner's Engineer
- Construction and Operations Monitoring
- Operating Portfolio Review and Optimization
- Financial Model Development and Review
- Performance Projections
- Environmental Compliance and Planning
- Contracts Review
- Testimony
- Fleet Benchmarking and Analysis

ACRONYMS, ABBREVIATIONS, AND UNITS

The following table is a listing of acronyms, abbreviations, and measurement units used in this report.

List of Acronyms and Abbreviations	
Acronym	**Name**
AGA	American Gas Association
CG&E	Cincinnati Gas &Electric
CGT	Columbia Gulf Transmission
CIP	Capital Improvement Plan
CNG	Compressed Natural Gas
DOT	Department of Transportation
Dth/h	dekatherms per hour
EIA	United States Energy Information Administration
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
HD	Heavy Duty
HDD	heating degree day
KOT	Kentucky Ohio Transmission
LDC	local distribution company
LNG	liquefied natural gas
MACT	Maximum Achievable Control Technology
MAOP	maximum allowable operating pressure
Mcf	thousand cubic feet
MMcf	Million cubic feet
Mcfh	thousand cubic feet per hour
MD	Medium Duty
NGVs	Natural Gas Vehicles
PUCO	Public Utility Commission of Ohio
TET	Texas Eastern Transmission
TGT	Texas Gas Transmission
TIMP	Transmission Integrity Management Plan
UPS	United Parcel Service

Table of Contents

Section *Description* *Page*

List of Appendices

List of Figures

List of Tables

Exhibit *Description* *Page*

1 Executive Summary

1.1 Introduction

Lummus Consultants International, Inc. (Lummus Consultants) was retained by Duke Energy Corporation (Duke Energy) to perform a detailed analysis of Duke Energy's existing Ohio and Kentucky transmission and high pressure distribution systems to determine supply reliability, forecast future needs and provide recommendations for a 20-year capital improvement plan (CIP). The results of the analysis are summarized in this Gas System Master Plan including a recommendation on the most-effective and least-cost capital improvements to Duke Energy's high-pressure gas transmission system for the next twenty years of operation. Included in the capital improvements are new and/or modernized feeder lines/higher-pressure delivery lines, and required peaking and/or storage facilities. Also included in this Gas System Master Plan study is a determination of the future use or disposition of Duke Energy's existing propane-air peaking plants and their underground storage facilities.

Lummus Consultants, through its legacy companies, including Stone & Webster Management Consultants, Inc. and Shaw Consultants International, Inc. has a history of over 100 years of providing engineering, construction, and consulting services related to the energy industry. There is no phase related to the transportation and distribution of natural gas that has not been handled fully and satisfactorily by Lummus Consultants from the earliest days of manufactured gas to the modern era of transcontinental and international gas projects. Lummus Consultants participated in the development of the Texas Gas Transmission, Transcontinental Pipeline Company, and TransCanada Pipeline Company systems. These assignments were conducted from the original market analysis extending through regulatory hearings to construction and operation. Lummus Consultants has extensive experience in natural gas transmission and distribution, including computer-based pressure-flow modeling of the piping structure, peaking facilities, and compressors.

Lummus Consultants employs engineers with experience working with gas utilities in areas including consulting, design, procurement, and construction management services. In the United States we have completed assignments for Vectren, Columbia Gas of Kentucky (a NiSource company), Columbia Gas of Pennsylvania (a NiSource company), Cinergy Corporation (Cinergy) (acquired by Duke Energy), Iroquois, Con Edison, KeySpan (a National Grid company), WE Energy, Tennessee Gas (now owned by Kinder Morgan), and Gulfstream. Our work for Cinergy, Vectren, Columbia Gas of Kentucky, and Columbia Gas of Pennsylvania included an independent technical review of the gas system. We have compared our clients' planning and expansion strategies to similar industry peers using our best engineering judgment. Our independent reports have been used to support and supplement our clients' capital improvement plans for rate case purposes.

Lummus Consultants provided consulting services in conjunction with the potential acquisition of the gas and electric utility in Montana by Babcock & Brown, the pipeline assets owned by El Paso Merchant Energy by WestLB, and most recently the potential acquisition of a large gas utility in New Mexico.

1.2 Overview

In 2005 Duke Energy and Cinergy merged to create an energy company with a portfolio of electric and gas businesses. Cinergy had been formed in 1994 by the merger of Cincinnati Gas & Electric (CG&E) and PSI Energy, Inc. (PSI). In 1989 CG&E had won a settlement with its primary natural gas supplier, Columbia Gas Transmission Corporation. As a result of the settlement CG&E gained exclusive control of the local pipeline market through a newly won right to buy 32 percent of a feeder pipeline into the Cincinnati market. Later 100% control was gained and the feeder line was renamed K.O. This review consists of an analysis of Duke Energy's high-pressure transmission lines and peaking facilities in the former CG&E service territory for the purpose of developing an independent recommendation for a twenty-year Gas System Master Plan.

Duke Energy supplies up to 43,000 Dth per hour (daily peak hour flow) to approximately 535,000 current customers in the combined Ohio and Kentucky service territory. The gas is received into Duke Energy's system from twenty-two stations that connect with several interstate pipelines. All of the stations, except for a key interconnect in the south, are located in the northern part of Duke Energy's service area, bringing gas to Ohio and Kentucky. Gas is transported throughout the service territory by a connected array of high-pressure steel pipelines bearing a wide range of maximum allowable operating pressures (MAOPs) and pipe diameters. These lines have been constructed at varying times over the past half-century or more, and have been upgraded continually.

In past years Duke Energy has prepared various types of capital improvement plans for their high-pressure lines, for a variety of time horizons, and for particular portions of their system. However, we understand this Gas System Master Plan is the most comprehensive twenty-year, review and future plan that has been formulated for the Duke Energy system. Benefits from this plan are expected to include enhanced transmission flexibility over many areas of the system, thereby increasing reliability of supply to mitigate undesirable results of supply transportation restrictions and upsets. Increased flexibility also allows customers a wider range of nomination choices over the 22 gate stations connected to interstate pipelines. This should result in lower-cost gas for all customers including those purchasing their supplies through third-party suppliers, such as those available in Ohio's CHOICE program. By time-staging the recommended improvements, Duke Energy will also be able to integrate a wide range of important local distribution company (LDC) activities, including improvements in its lower-pressure delivery system, capturing new areas of business, establishing new customers, and securing economical, objective-oriented, supply contracts.

1.3 Background

1.3.1 Capital Improvements

Duke Energy and its predecessor gas distribution companies have served the greater Cincinnati, Ohio area for more than 175 years. Throughout this time Duke Energy has made countless capital improvements; many aimed at expanding its energy delivery system. For a healthy and growing LDC, expansion improvements are not optional. As a regulated LDC, with an obligation to serve its customers, Duke Energy must undertake capital expansions, as required to effectively provide the supply and pressure needs of an ever-changing market and ever-ageing system. These capital improvements are essential in maintaining an operational infrastructure providing reliable supply, while positioning Duke Energy with the ability to capture emerging markets of the future.

1.3.2 Gas Master Plan

A wide range of potential expansion alternatives have been considered by Duke Energy in recent years to address:

- Decreasing interstate supplier pressures
- Decreasing pressures within Duke's system
- System flow inflexibility
- System reliability
- System growth restrictions
- System growth demographics

As Duke Energy considers ways to address these issues, a variety of solution options have been studied as potential capital improvement projects. It is understood that while solving one issue with a capital expansion improvement, other segments of the system are likely affected, resulting in potential economic and operational benefits. Examples are the elimination of outdated Propane-air plants, improving balance/cost of supply, or obviating the need for an otherwise planned capital investment. Duke Energy understands the importance of developing a master plan to help guide in a coordinated manner their capital investment plans for their energy-supply assets over a longer time frame. This Gas System Master Plan will play a key role in positioning Duke Energy to continue to provide reliable supply to a changing demographic market for years to come, and at the same time position Duke Energy to be able to capture emerging markets of the future.

1.4 Project Approach

Lummus Consultants performed an independent review of the system operations, and conceptualized major capital improvements in the energy delivery system to improve the system flexibility and reliability, while serving expected customer demand over the next twenty years. These improvements include those that have been considered in-house by Duke Energy, in addition to the ones introduced by Lummus Consultants. Lummus Consultants analyzed the proposed projects following a thorough review of Duke Energy's long term demand forecast and system operations capabilities. Each proposed project was analyzed for hydraulic operability through a series of computer runs performed to Lummus Consultants' specifications. Computer runs were made on Duke Energy's licensed SynerGEE (Stoner) pipeline simulation model representing its high-pressure pipelines in the Ohio and Kentucky service territory. These computer analyses are based on a series of twenty-year demand profiles, which were developed by Lummus Consultants representing a probable range of future demand.

Lummus Consultants first verified Duke Energy's demand forecast of future usage by customer class covering the time period 2014 through 2024. The peak-day portion of this forecast was extrapolated to cover the time period through 2035. Lummus then analyzed the flow and pressure capabilities of Duke Energy's existing high-pressure energy delivery network in its combined Ohio and Kentucky service territory to meet the projected demand and ensure reliability of supply to all customers. Results indicated that peak-day customer demand could be met in all segments of Duke Energy's system if certain new line expansions were made. Secondly, Lummus Consultants developed a high-case demand alternative forecast that envisions the entry into emerging markets; some of which Duke Energy cannot currently serve in a meaningful way due to the presence of propane (from Duke Energy's propane-air peaking plants) in system gas that reaches a large portion of its service territory during winter periods.

Lummus Consultants then developed an independent plan for a capital investment program that would permit Duke Energy to continue to meet customer needs (both low-case and high-case demand) throughout the forecast period. In order to formulate this plan, Lummus Consultants conducted a thorough review of the current capabilities of the piping network and directed a computer-based review of the benefits and mutual interactions of a range of objectives-oriented, potential capital improvements. Each potential improvement was tested in Duke Energy's transmission system flow model under peak-day conditions for future years, to determine its contribution to the study objectives and effect on Duke's current plans and operations. For this study, Lummus Consultants considered Duke Energy-identified capital improvement plans limited to no less than $5 million in estimated cost.

1.5 Proposed Master Gas Plan

The overall combined improvements selected for the Gas System Master Plan are shown in the following table:

Table 1: 20-Year Gas Master Plan for Transmission System & Peaking Plants

	EXPANSIONS AND PEAKING CAPITAL EXPENDITURES	ESTIMATED COST ($MM) MINIMUM		ESTIMATED COST ($MM) MAXIMUM	
1	ONE OF 7 RELIABILITY EXPANSION OPTIONS	$ 52.2		$ 401.6	(1)
2	G7BIGBON CONNECT UL02 TO AM03	$ 7.5		$ 19.0	
3	GC338 EXTEND C338 FROM BETHEL TO SS00 (UNLESS E-1 EXPANSION ELIMINATES NEED)	$ 50.0		$ 100.0	(2)
4	POSSIBLY DECOMMISSION BOTH PROPANE FACILITIES AND CAVERNS AFTER ONE RELIABILITY OPTION IS INSTALLED	$ 5.0		$ 7.0	(3)
	TOTAL 20-YEAR CAPITAL EXPANSION PLAN	**$ 114.7**		**$ 527.6**	

NOTES:
(1) Min & Max costs are averages of low and high cost estimates for least expensive (C-1) and most expensive (C-2/W-2) options.
(2) GC338 Expansion is still required for all potential new expansions, except possibly not required for expansion E-1.
(3) One time write-down upon abandonment of Erlanger and East Works plants

One key objective in the Gas System Master Plan recognizes that the current state of the system is vulnerable to risk of extensive customer curtailment and/or shut-in. This is primarily due to the excessive reliance on gas supplies that enter the system through a single station in the south. The southern meter and regulating station, Foster Gate Station (Foster), typically handles up to 50 to 60 percent of Duke Energy's natural gas demand, owing not only to contractual arrangement, but predominantly to the system configuration currently preventing available gas from the north to reach the southerly extents of the system. If a failure of the system at or around the area of Foster occurred during the winter or shoulder months, roughly 50 percent of Duke Energy's customers would be affected. The alleviation of this vulnerability is seen as a key impetus in implementing prudent system enhancements to augment gas supply sourcing from the north, where connections to interstate gas pipelines, through 21 gate stations, currently exist. Therefore each system expansion possibility was analyzed for its ability to lower the risk of customer outage as well as for its ability to serve future loads.

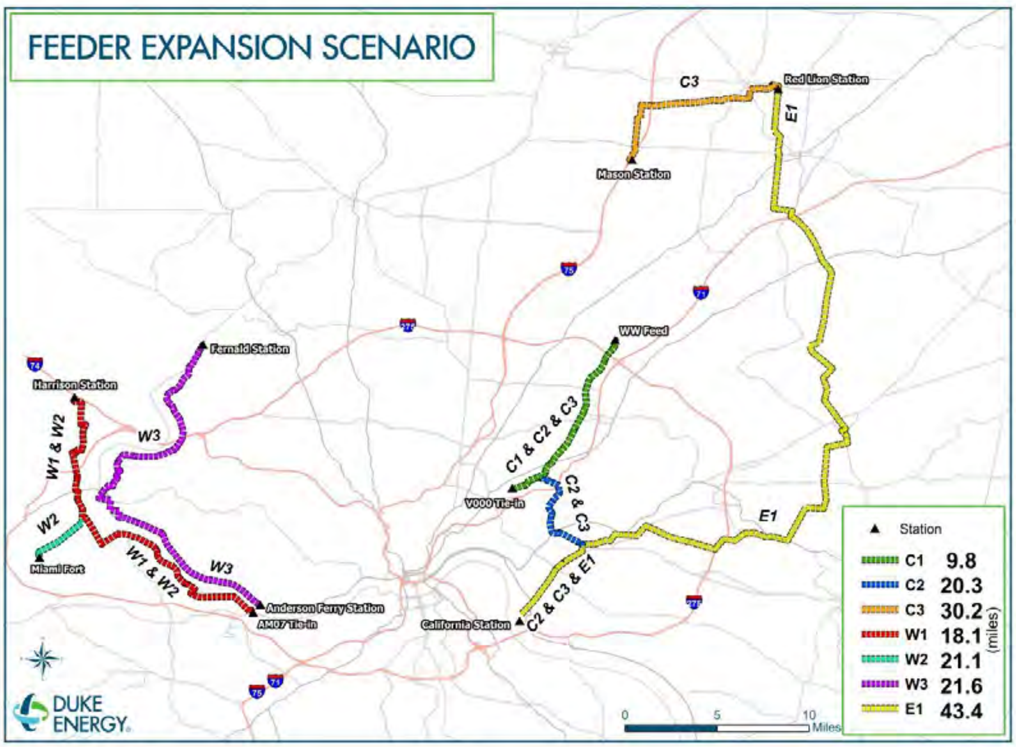
1.6 Findings and Conclusions

Lummus Consultants developed and analyzed the expected growth trends for demand throughout the next twenty years. We also reviewed Duke Energy's ability to meet this forecasted demand with its currently configured high pressure transmission system, as well as with an enhanced transmission system, wherein capital improvements, as selected in this study, have been implemented.

Key findings by Lummus Consultants are that:

- The greatest threat of customer outage in Duke Energy's current supply system can be substantially reduced, and even virtually eliminated through implementation of certain capital expansion projects detailed in this Gas System Master Plan. The following map depicts the seven basic expansions, in combination totaling nine expansion plan options, that Lummus Consultants has developed to reduce the risk of customer outage at Foster, and simultaneously provide increased flexibility for Duke Energy's transmission system:

Figure 1: Feeder Expansion Scenario



- The peak load forecast anticipates varying levels of certainty that the system will exceed its total peak or its firm peak. The modeling and planning work of this report considers the 1% probability of exceeding firm peak as the criteria against which to plan. The trend in the forecast is very flat on a going-forward basis, with an annual growth rate of roughly one half of a percent.

- The major impediment to penetration of certain growth markets (particularly the NGV market) by Duke Energy can be minimized or even eliminated, through implementation of the peak-shaving recommendations in this Gas System Master Plan. A summary of the capital and annual cost requirements for identified major peak-shaving options is presented in the following table:

Table 2: Cost Comparison of Peaking Options

	COST COMPARISON OF PEAKING OPTIONS AT DUKE ENERGY ($ Million) (BASIS: 85,000 Dthd Peaking Capacity)					
	CURRENT P-A PLANTS		NEW LNG PLANT (2)		PIPELINE PEAKING SRVC	
COST ELEMENTS	Investment (1)	Annual Cost (1a)(1b)(1c)	Investment (2a)	Annual Cost (2b)	Investment Pipeline (3)	Annual Cost (3a)(3b)
Investment Capital; Annual Levelized Fixed Charge at 12% est	10.1	1.2	136.0	16.3	82.0	9.8
Contract Demand Charge	-	-	-	-	-	1.0
Inventory, Interest on Inventory at 12% est.	5.0	0.6	4.3	0.5	-	-
Annual commodity cost of sendout	-	5.2	-	0.0	-	2.2
O&M (Labor and Materials)	-	1.4	-	0.0	-	-
Utilities, incl. Fuel	-	0.1	-	0.0	-	-
Propane Plant Decomissioning One-Time Avg Cost Write Down (4)	-	-	6.0	-	6.0	-
New Markets Opportunity Cost	-	0.6	-	-	-	-
TOTAL COSTS	**15.1**	**9.1**	**146.3**	**16.8**	**88.0**	**13.0**

(1) Includes $9.1MM Erl vaporizer budget through 2017; EW security project, compressor controls, D-line relo, valve replace; Total 9 MMgal Storage: each
(1a) Estimated cost of Propane sendout prior season as equated to required of pipeline peaking volume at btu ratio of 1.4 propane-air/natural gas
(1b) Labor & Materials estimated by C. Fritsch. Erl electric at $4,055/day, EW at $5,141/day for 7 days of sendout
(1c) New Market Opportunity Cost ranges from $353k in 2021 to $2,003k in 2035 per Lummus Demand study
(2) Rough order of magnitude estimate as per CBI business development for 1Bcf storage, 85MMcfd sendout and 5MMcfd liquefaction; incl balance of plant
(2a) Assumes Inventory stored 90% of 1,062,500 dth at $4.50/MMBtu, augmented by winter liquefaction
(2b) Assumes sendout gas cost of $4.5/MMBtu
(3) Estimated System Investment of average high and low cost, Scenario C-1
(3a) Estimated winter 25-day supply of 2,125,000 dth; Pipeline Demand Charge estimated by J. Kern for 2014, to range from $0.6 to $1.4 million
(3b) Cost of gas calculated by J. Kern for 2014 sendout at Lebanon price average $7.1 per MMbtu equated to Propane sendout volume
(4) Estimated at $5 to $7 million

- Annual costs for the options shown in the previous table indicate that while the economics favor the continued use of the propane plants for peaking service, the long term continued use of these plants is not recommended, as discussed in this report. Long term operations for peaking supplies and enhanced overall reliability, flexibility and market growth, favor the use of short-term (e.g. 25-day) interstate supply contracts once Duke Energy implements one of the nine new expansion options that will permit accessing these types of firm supplies at locations other than through Foster.

- Increased flexibility to accept deliveries from a wider range of interstate connections could provide lower-cost supplies for all customers, including those Ohio customers electing their supplies through the CHOICE program.

- The selection of an appropriate system expansion would consider numerous aspects, to include reliability, flexibility, cost, constructability, regional growth, synergies with planned pipeline upgrades, safety, ROW issues, etc. Lummus Consultants recommends a selection screening, where Duke Energy might envision a ranking scheme of the expansion options presented. This scheme would identify relevant ranking categories and assign ranking weights to each category. An example of how such a ranking scheme would be structured is presented in Table 20, described in Section 9 of this report. Additional selection tools might involve the implementation of a Monte Carlo Simulation, where impacts of risk affect the possible outcomes of decisions.

In summary, Lummus Consultants suggests that the capital improvements recommended in this study be used as a road-map for Duke Energy in planning future system modifications. We also suggest that this Gas System Master Plan be updated at regular intervals to include changes in market demographics, changes in technology, changes in Department of Transportation (DOT) regulations, changes in piping developed through Duke Energy's Transmission Integrity Management Plan (TIMP), and changes in Duke Energy's mission as formulated through its Public Utility Commission (PUC).

2 Historical Trends

2.1 History of System Supply

When Duke Energy's predecessor gas companies in the Cincinnati area were first formed, over 175 years ago, their source of supply was entirely different than it is now. At that time, interstate pipelines did not exist in the area, so all of their gas was produced on site by a manufactured gas process, which converted coal to gas.

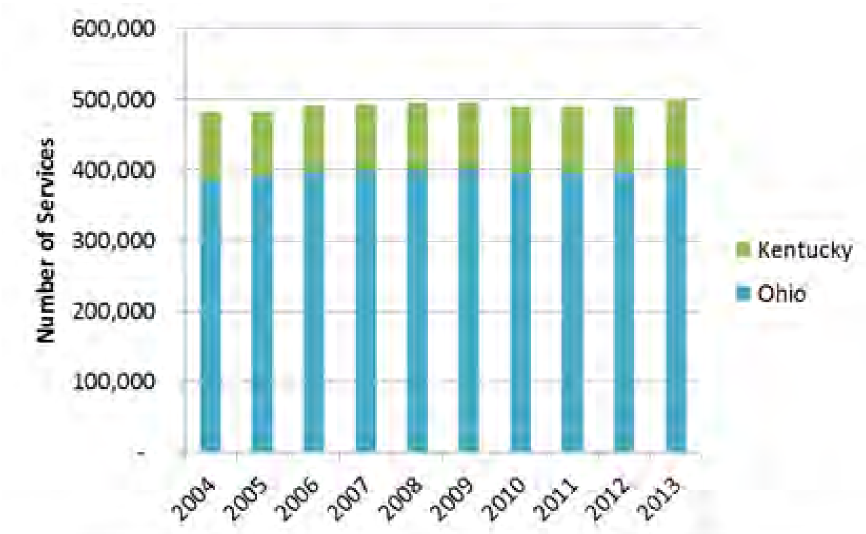
In the early-1900s, as interstate pipelines were constructed to transport newly-discovered natural gas from Texas and Oklahoma to northern cities, the Columbia interstate pipeline brought gas to what is now the Kentucky portion of Duke Energy's service territory. As Duke Energy's manufactured gas facilities were gradually decommissioned, Columbia became the sole source of gas supply for Duke Energy's system. History has proven that this sole-sourced supply risk was manageable by the operating and customer appliance and service groups in Duke Energy's predecessor companies. However judged by today's standards, it would be considered imprudent for a major gas company to be exposed to the risks of relying on only one company to provide gas supply if it was possible and feasible to connect to other pipeline suppliers. A complete, or even partial, interruption of supply from a sole supplier would have serious consequences, particularly if the interruption occurred during winter periods. In addition to placing customers at inconvenience and discomfort, such an outage could require weeks or months to purge gas lines and restore customer service, since gas appliances at interrupted customers would necessitate a service call to re-light gas pilots.

In the late-1900s, natural gas was discovered in the west and other portions of the U.S. and imported to the U.S. from Western Canada. This resulted in a number of pipelines traversing Ohio in the northern portion of Duke Energy's service territory, creating a gas pricing and supply hub at Lebanon, Ohio. This is an extremely fortuitous circumstance and Duke Energy has aggressively contracted for gas supply from these northern pipelines utilizing the presence of the Lebanon hub to diversify its sources of gas. Today Duke Energy has twenty-one of its twenty-two gate stations located to accept gas from the north. However, due to system piping limitations, Duke Energy has not been able to reduce the amount of supply required from the single southern gate station (and its single supplying pipeline) to a level below about 50 percent of its entire system requirements. Thus, Duke Energy's reliability risks of interrupted supplies from a single source has been markedly reduced, but still remains as a major exposure to supply interruption.

2.2 Customer Growth

Duke Energy has experienced limited customer growth over the past decade. Recent counts of its customers show a stabilizing market, as indicated in Figure 2, which displays the number of service lines reported to the DOT annually.

Figure 2: Customer Count for Ohio and Kentucky (2004-2013)



Data Source: Annual DOT Reports

A stable customer count is typical of urban-centered LDCs, in contrast to some suburban-based LDCs that have substantial customer growth into new or developing areas.

In addition to a stable customer count, Duke Energy's gas volumes supplied to customers have also stabilized. Part of this flat sales volume is due to the continuing use of more efficient appliances by Duke Energy's customers. Some of Duke Energy's flat growth in demand stems from energy efficiency programs, better home insulation, and more efficient natural gas appliances. In addition, that has been a limitation to capture emerging new markets, particularly where propane content in the gas poses a problem. The presence of propane-air flowing throughout extensive segments of its system during parts of the year poses restrictions for some end users. For instance, end uses such as NGV require recompression of delivered gas to very high pressure levels. The presence of even small amounts of propane in the gas can result in liquid formation at high pressures. Since liquids are incompressible, the end result is damage to the user's compressor.

2.3 System Reliability

A critical responsibility entrusted in Duke Energy, is to assure that service to its firm, temperature-sensitive customers be maintained through a system that is capable of overcoming virtually all conceivable, realistic threats to interruption. The ability to maintain continuous gas service when these interruptions occur is denoted as the reliability of system supply.

Emergencies such as line washouts, earthquakes, landslides, or other natural phenomena have all been known to occur; so too have pipeline damages caused by intentional sabotage, outside contractors, other utilities, or other third-parties. Additionally, emergencies of these types can also occur to the lines of the Interstate pipeline suppliers of gas to Duke Energy, even hundreds of miles upstream of the Duke Energy system. Any of these incidents could threaten Duke Energy's ability to continuously supply gas to its customers.

Duke Energy employs a number of safeguards against loss of supply. These include the utilization of its emergency gas supplies as a partial supplement within its own system through operation of several propane-air peaking plants, and through the temporary use of line-pack from its high-pressure lines. With multiple pipelines and gate stations supplying its system, Duke Energy may also switch receipt points, as may be afforded by the flexibility of its system and the ability of supplying pipelines. Duke Energy also is able to curtail significant gas volumes to its interruptible customers, and during emergencies is able to request customers to limit their gas takes. Further, Duke Energy participates in an industry plan whereby other gas utilities can share their supplies with Duke Energy during an emergency. Duke Energy is also guided by the PUC-approved curtailment priority plans to be enacted as a last resort.

Another very important safeguard is Duke Energy's flexibility to reroute gas supplies around impediments that may occur in its piping system, and even draw upon gas from different suppliers if the problem exists upstream of the company's system. The latter ability (drawing gas from different pipelines and/or at different gate stations) has shown improvement over time through strategic capital expansions in parts of their pipeline system, but still needs to be further improved in order to reduce the risk of a high number of potential customer outages. This reliability issue is judged by Lummus Consultants to still be a concern for Duke Energy and its customers.

Lummus Consultants observes that the major reliability risk in Duke Energy's system at this time is due to the excessive reliance on gas supplies that enter the system through a single station in the south. Since the startup of initial gas service over a hundred years ago, this risk has been reduced from the possibility of incurring outages throughout the entire system, to its present state of potential loss of service to customers numbering in the neighborhood of approximately 300,000, according to Duke Energy's latest estimates. Outages of this magnitude could occur if a complete supply failure happened on a very cold day near or upstream of Foster. This is considered to be a substantial risk in Duke Energy's current piping system. Somewhat smaller, but still significant outages, could also occur on virtually any day of the year, not just on very cold days, should this type of failure occur at or near Foster.

If an interruption of the magnitude mentioned above actually occurred, Duke Energy would have to mount a tremendously large reconnection effort. Service technicians and operations staff would have to enter each customer's premise to assure that all pilots were relighted and all air was purged from customer gas lines. This large of an effort would take many months to implement. Obviously, if such an outage occurred during wintertime, customers' health and lives would be at risk, due to the low temperatures and lack of natural gas for space heating, hot water, cooking, etc.

Duke Energy, like all gas utilities, has an obligation to supply gas to its firm customers. Key to fulfilling this obligation is the challenge of ensuring that its natural gas system is reliable and sufficiently reinforced to provide uninterrupted gas service in an economic manner. In order to address the potential outage risk in the southern portion of Duke Energy's system, reliability was elevated to one of Lummus Consultants' major considerations in preparing this Gas System Master Plan.

As part of our review, Lummus Consultants requested Duke Energy to conduct numerous system network gas flow analyses for various pipeline sizes, locations, and system conditions. The selected capital expenditures that enhance system flexibility are also seen as reducing reliability risks. The propensity to reduce reliability risk was considered along with the assessment of the various individual system improvements identified by Duke Energy in their expansion considerations.

Lummus Consultants has formulated a twenty-year Gas System Master Plan that is capable of reducing the risk of outages as a means of mitigating the impacts of supply failure near Foster. In fact, a number of the proposed pipeline expansion options could reduce this risk entirely.

3 Demographic Study Results

Lummus Consultants was tasked with completing a demographic study for Duke Energy's Ohio and Kentucky service territories to identify for natural gas the highest growth potential areas and the potential loss of business. The demographic study provided input to and relied upon information in the Gas System Master Plan study tasks described in other sections of this report. The demographic study considered proposed gas infrastructure improvements; potential areas of new growth based on future capital improvements; existing system capabilities; and the ability to support future growth. The study evaluated the long-term forecast that is already in place for gas volumes and customers through 2024 and considered future time periods through 2035.

Lummus Consultants investigated the anticipated system growth on the Duke Energy system in order to identify growth in demand from new technology or new application opportunities. To provide this potential growth assessment, Lummus Consultants worked with Duke Energy personnel to understand the current demographics of the systems, reviewed the current forecasting approaches utilized by Duke Energy to understand how new technology is captured, and investigated potential additional opportunities for expansion of demand. Our analysis adopted Duke Energy's forecast as our "base case" projection given that, based on our review, that forecast offered the most current "business as usual" perspective. Lummus Consultants documented the potential additional growth that may be realized from policy changes and new technology adoption in the Duke Energy territory. As part of this demographic study Lummus Consultants explored gas uses such as natural gas vehicles (NGVs), electric power plant generation, fuel conversions to natural gas, and distributed power generation.

3.1 Information Sources

Lummus Consultants reviewed information provided by Duke Energy, including historical and projected natural gas use by its customer base. Historical customer count data was provided over the five and a half year period from 2009 through June of 2014 for all customer segments (residential, commercial, industrial, etc.) and customer sub-segments (full service versus transportation). Historical data also included Duke Energy Ohio and Duke Energy Kentucky system load data in thousands of cubic feet (Mcf) on a daily basis from 2009 through September 2014, residential usage for both states on an annual basis from 1991 through 2011, and commercial and industrial load on a monthly basis for 2013. Finally, the team reviewed a list of the coldest 100 days, corresponding to the highest load days within the last five years.

On a projected basis, Lummus Consultants was provided with a 10-year annual peak forecast for both states as well as for the combined system; each of these three system perspectives were described both in terms of total peak as well as firm peak (2014 - 2024). We also reviewed the 25-year monthly send out forecast (2014 - 2039). Both the peak and send out forecasts were prepared by Duke Energy with a 2014 spring basis as noted in a forecasting methodology entitled "*Gas and Natural Gas Demand Forecasts for Gas Distribution Companies Serving More Than Fifteen Thousand Customers*", which described the methodology used to develop these forecasts. The forecast utilizes techniques that are standard in the industry for projecting future gas energy and peak. Essentially the forecast relies on economic forecasts nationally and locally including employment projections, population changes, and general economic parameters coupled with equations, developed using historic relationships through statistical techniques to project future usage. The model statistics that are used to assess the reliability of the underlying relationships to project the forecast parameter were provided as part of the methodology documentation appendices and are reasonable and in line with industry statistics for all classes of customer projections. The resulting forecasts are modified for conservation due to anticipated efficiency and conservation due to price changes – which is a necessary component of a forecast. We followed up with a conference call with the forecasting team and that conversation and additional information confirmed our overall perspective that the approach used by Duke is consistent with industry practice and relies on standard industry information and reliable economic projections. Based on our review of the methodologies used and the data provided, Lummus Consultants concluded that the spring 2014 forecasts are reasonable and sufficient for use as the Gas System Master Plan's base case, or what is termed here as the "business as usual" case. It is important to note that a majority of the assumptions driving the forecasts provided to Lummus Consultants by Duke Energy rely on confidential information provided to Duke Energy by Moody's Investor Services (Moody's) for which Lummus Consultants did not have access to the data due to the confidential and proprietary status noted by Moody's.

Lummus Consultants investigated the potential for changes in Duke Energy's service territory and customer base that could impact future natural gas usage, including customer and market growth, energy efficiency, potential for loss of business in the region, and adoption of new gas consuming technologies. An important consideration in projecting changes in natural gas use forecasts is the review of industry information. Lummus Consultants reviewed the industry for NGV opportunities and other potential new natural gas use opportunities that could drive an increase in usage, such as new large industrial and residential customers and power generation stations.

3.2 Historical Data

3.2.1 Customer Count

As referenced earlier, Duke Energy's customer base for natural gas service has held relatively constant in terms of number of customers over the past several years. With the introduction of CHOICE in Ohio more than a decade ago, residential customers now have access to natural gas supply options that are delivered through their LDC; this is much like the access that commercial and industrial customers have due to the buying power and leverage of their size and procurement business processes. Energy Choice Ohio quotes that "*nearly 2.4 million electric customers and 1.7 million natural gas customers are already participating either individually or with aggregation groups*".[1] In reviewing the historical customer count data provided by Duke Energy, Lummus Consultants observed a consistent trend toward increasing numbers of "transportation" customers (i.e., customers that purchase natural gas from suppliers other than Duke Energy, and then rely on Duke Energy to deliver the natural gas), and fewer "full service" customers (i.e., customers that buy the natural gas commodity and the delivery services all from Duke Energy).

Despite the shift in these two customer types, the total customer numbers have remained relatively constant over the past five years, with only seasonal fluctuations such as an increasing number of customers in the winter months. Figures 3 through 5, below, provide an illustration of these customer count trends in each of the three primary customer segments: residential, commercial, and industrial. In each figure, the dark gray line represents total customers for the combined Duke Energy Ohio and Duke Energy Kentucky service territories. The dashed blue lines represent Duke Energy Ohio customer counts, with the dark blue line depicting full service customers and the light blue line depicting transportation customers. The orange dotted lines represent Duke Energy Kentucky customer numbers, and the dark orange line represents full service customers whereas the lighter orange represents transportation customers. Kentucky does not have an energy policy like Ohio's "CHOICE" program, so residential customers do not have access to competitive natural gas markets, which explains why the light orange line is only present in the commercial and the industrial figures.

[1] Energy Choice Ohio website; http://www.energychoice.ohio.gov/Pages/About%20Choice.aspx; accessed in October 2014.

Figure 3: Monthly Residential Natural Gas Customer Counts, 2009 through June 2014

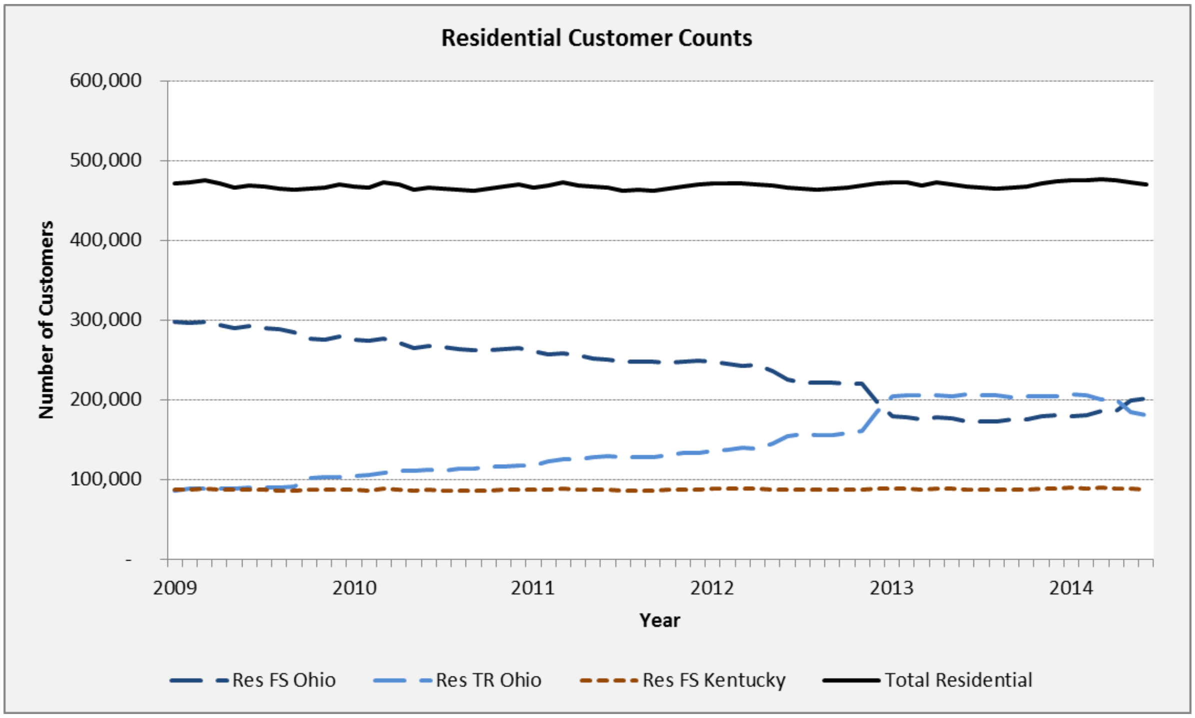


Figure 4: Monthly Commercial Natural Gas Customer Counts

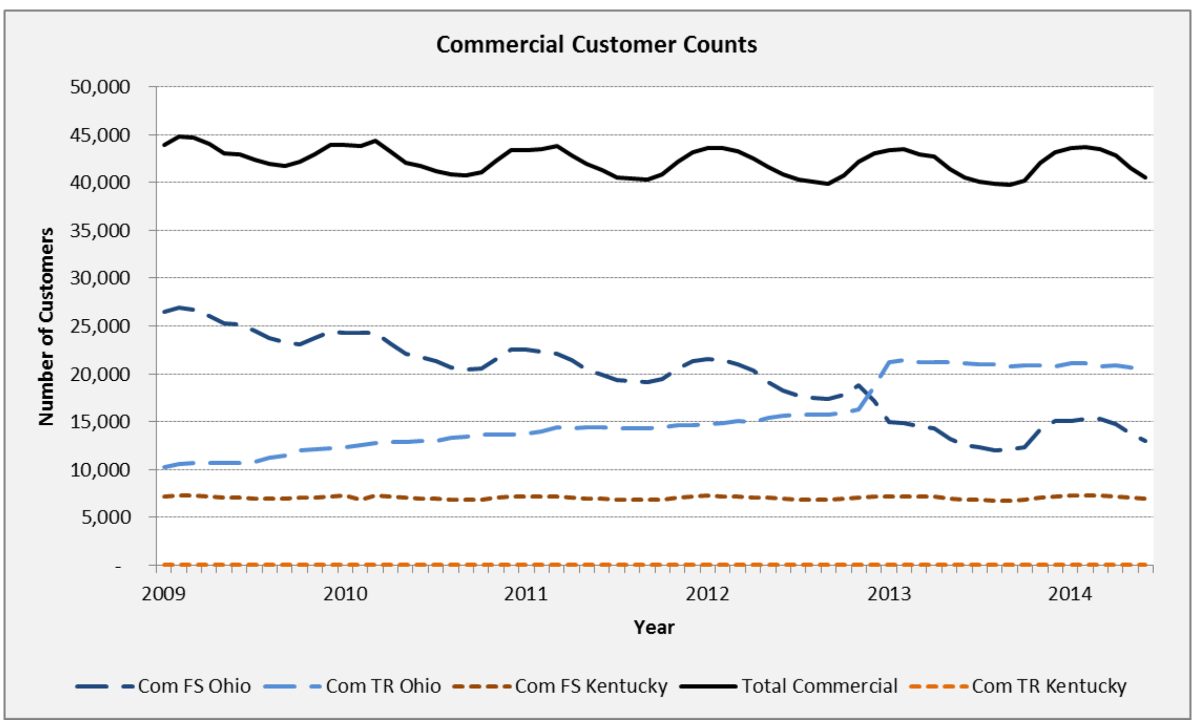
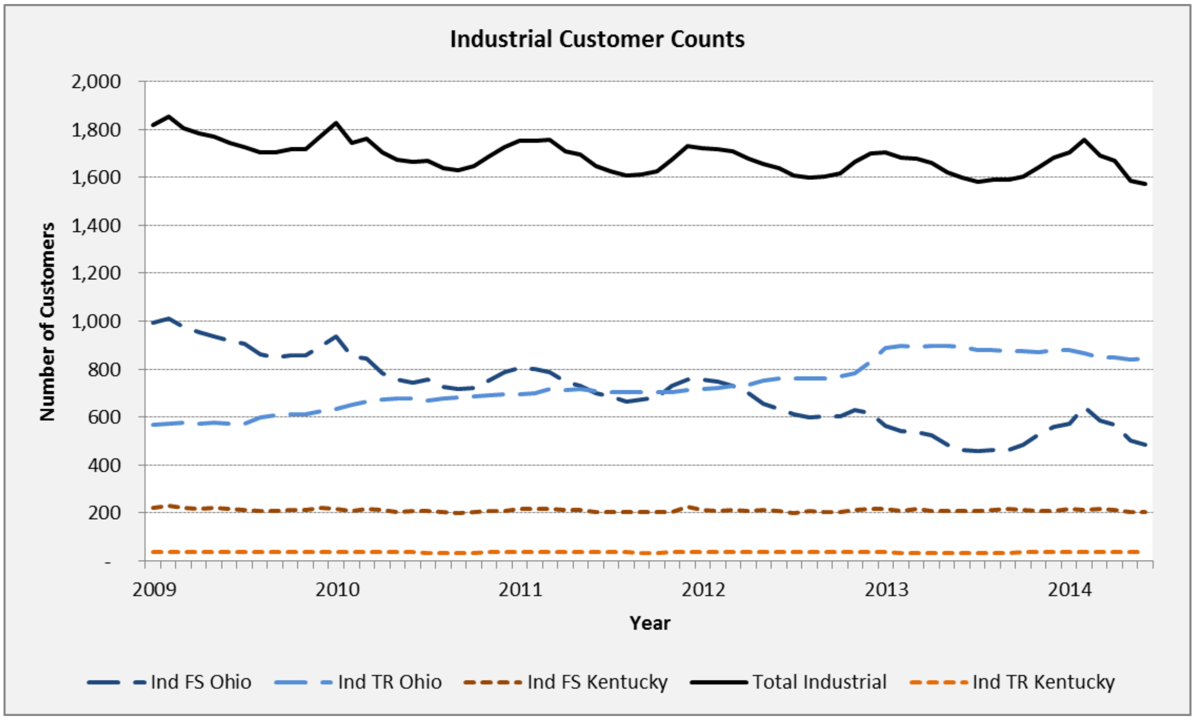


Figure 5: Monthly Industrial Natural Gas Customer Counts, 2009 through June 0214

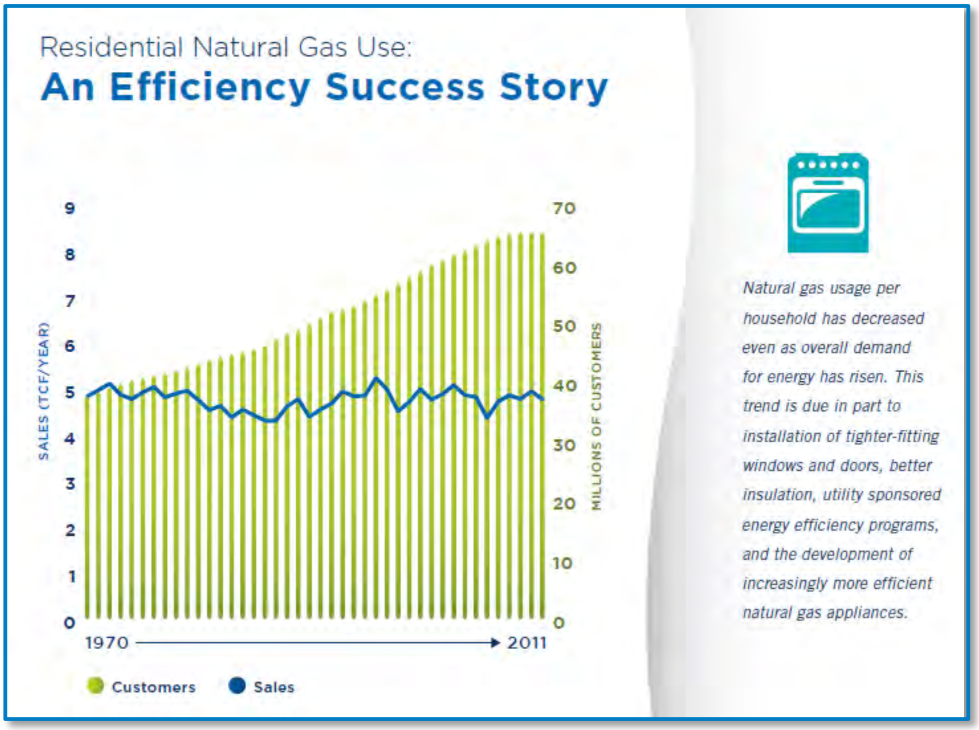


3.2.2 Residential Average Customer Use

Coupled with stable customer counts, there has been a consistent trend in recent years that would indicate that Duke Energy's customers have been using less natural gas on a per customer basis. This is consistent with an industry-wide trend toward more efficiency, both in the natural gas utility business as well as in the electric utility business. Figure 6 provides an excerpt from the American Gas Association's (AGA) "*2014 Playbook*"[2], which shows residential customer counts over the past 40 years plotted against natural gas sales over the same time period. Despite a rising trend in natural gas customers, the amount of natural gas sales have remained relatively constant, indicating that each customer is using less and less natural gas over time. The AGA points to utility-sponsored energy efficiency programs, better home insulation, and more efficient natural gas appliances as key drivers for this trend.

[2] American Natural Gas Association, "*2014 Playbook*", page 53, available at http://www.aga.org/our-issues/playbook/Pages/default.aspx .

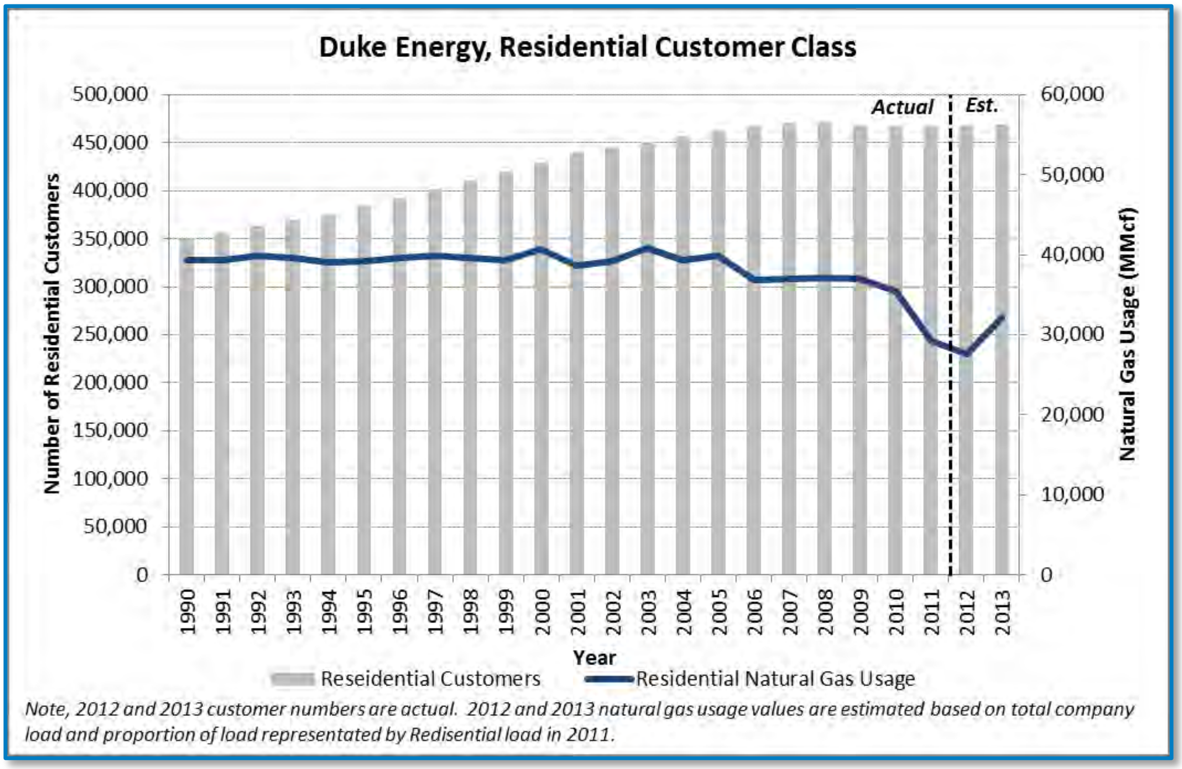
Figure 6: American Gas Association, Residential Natural Gas Use



Source: American Natural Gas Association, "2014 Playbook", page 53

Figure 7 on the following page describes Duke Energy's residential customer count versus natural gas sales over the 23 years from 1990 through 2013. Over the last five years, the customer count has held relatively constant. This is comparable to the stable trend in the customer count of the AGA figure above between about 2008 through 2011. The natural gas sales trend, however, is more downward trending within Duke Energy's residential service territory than the more flat trend presented by AGA, indicating that Duke Energy's customers may be using less natural gas per customer in the recent past than the average residential customer has decreased usage, as described in the AGA figure.

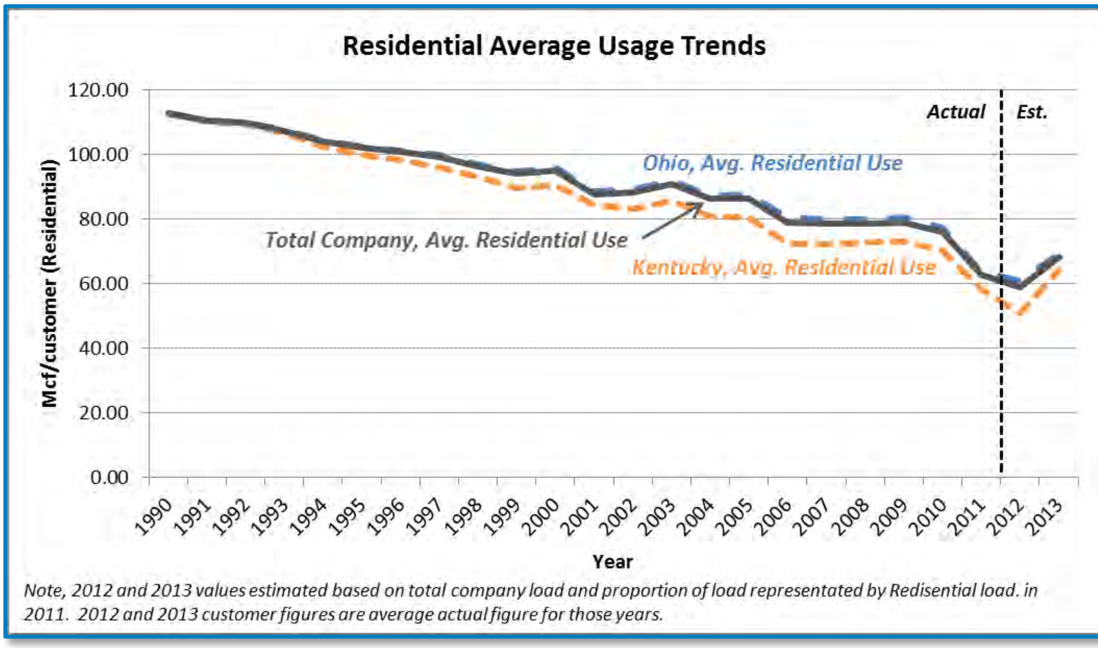
Figure 7: Duke Energy, Residential Natural Gas Use



Source: (1) Duke Energy, Residential Customer Counts for Duke Energy Ohio and Duke Energy Kentucky from 1990-2013; (2) Duke Energy, Residential Natural Gas Usage for Duke Energy Ohio and Duke Energy Kentucky from 1990-2011.

The gray bars in Figure 7 show the number of residential customers from 1990 through the most recent full year, 2013. The blue line represents actual residential natural gas usage through 2011. Equivalent information for 2012 and 2013 has been estimated here based on actual usage in these years for the entire Duke Energy system, and an assumption that the percentage that residential use represented relative to total use in 2011 (34% in Ohio, 39% in Kentucky) would hold constant. Plotting this information on an Mcf/customer basis for the residential class, Figure 8 shows that on the whole, Kentucky customers are reducing their average usage more than Ohio customers are, and over time, both service territories are trending downward (i.e., decreasing average usage per customer). Estimates in 2012 and 2013 indicate that this trend may have taken a temporary turn upward; but based on the data we are not able to confirm this trend at this time. In general, Lummus Consultants expects that there will be a continued pressure and focus on efficiency. Efficiency is driven by step changes in heating equipment and natural gas appliances, but also by more and more customer awareness of conservation efforts and new technologies that enable customers to manage their energy use in a low-impact way, such as programmable thermostats and mobile control on heating settings.

Figure 8: Duke Energy, Average Use by Residential Customer Class

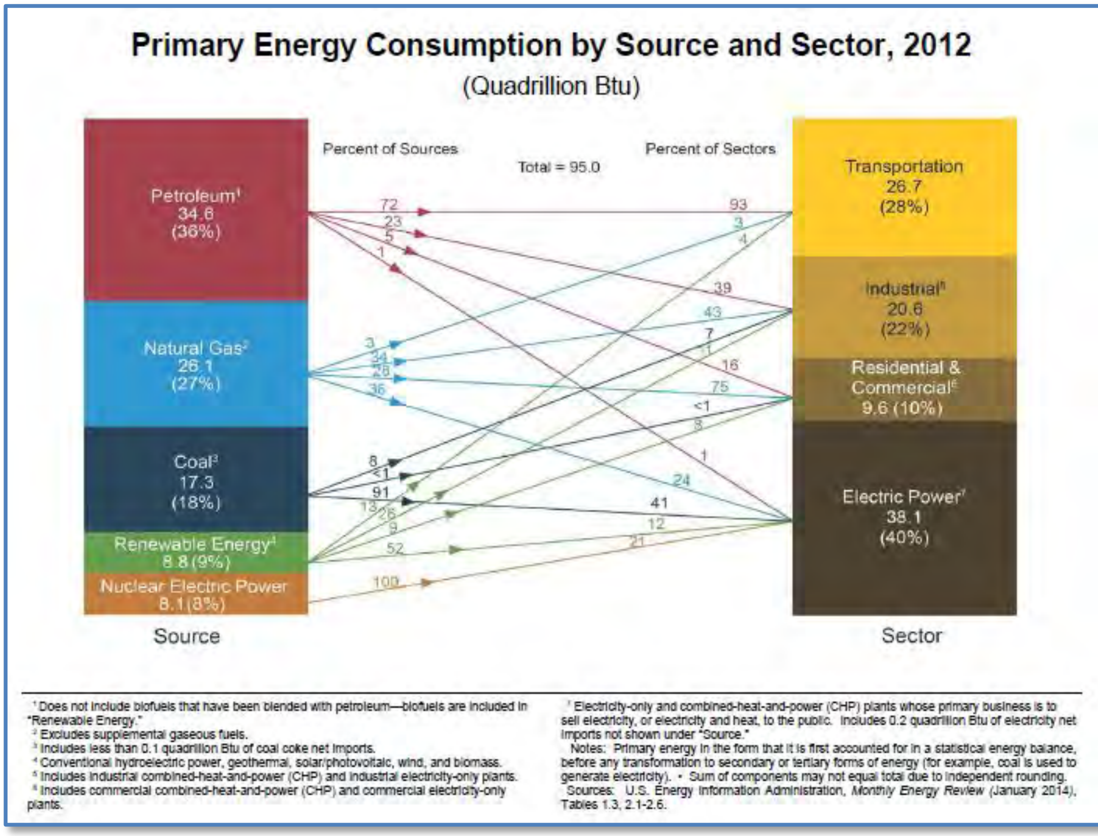


3.2.3 Natural Gas End-Uses

In considering potential new markets for the use of natural gas, Lummus Consultants reviewed the supply of natural gas by end uses from a historical perspective. The analysis presented in Figure 9 below, developed by the U.S. Energy Information Administration (EIA),[3] provides an illustration of U.S. energy use by fuel source at the left, and by end-use sector at the right. Within each column, energy use is defined on a percentage basis (for instance 36% of energy supply is *provided* by petroleum, as compared to other fuel sources, and on the end-use side, 28% of energy demand is *used* by the transportation sector as opposed to residential, or industrial, etc.). Shown with arrows are the relative percentages that tie the two columns together. For instance, coal represents 18% of the energy *supply* column of that, 8% is *used* in the industrial sector, less than 1% is *used* in the residential and commercial end use sector, and 91% is *used* in electric generation (for a total of 100%).

[3] U.S. EIA, "Primary Energy Consumption by Source and Sector, 2012", available at: http://www.eia.gov/totalenergy/data/annual/?src=Consumption-f6#consumption

Figure 9: Primary Energy Consumption by Source and Sector, 2012



Source: U.S. Energy Information Administration, "Primary Energy Consumption by Source and Sector, 2012"

When looking at the natural gas energy source, this analysis shows that natural gas is the predominant fuel used in homes and businesses (75%) and the industrial sector (41%), but that the largest potential "growth areas" would be in transportation (natural gas only serves 2% of that sector) and in electric power generation (natural gas only served 24% of that sector as of 2012). Note, with the technological advances in natural gas drilling and shale reserves exploration, the natural gas commodity has seen a downward pressure on pricing, except during high-demand times in the winter months. This market change is causing re-evaluation of natural gas use across many end-use sectors, but most notably there have been increases in natural gas use and conversion to natural gas in the electric power generation industry and a more rapid transition of some transportation assets and fleets toward use of natural gas. In both industries, natural gas represents a fuel source with lower carbon emissions as compared to the primary fuel in each sector; coal in the electric industry and petroleum in the transportation industry. International energy policy has, in recent years, shifted to a greater focus on reducing greenhouse gas emissions, and as such, there has been increased emphasis on low-carbon policies and other sustainability efforts throughout the U.S. business sector. Section 3.4, New Markets, provides more discussion of the transportation and electric power generation business opportunities for Duke Energy, in particular.

3.2.4 Natural Gas Seasonal Load Shape

Lummus Consultants reviewed the seasonality of Duke Energy's demand, which is in line with the seasonality shape of other LDCs, including large demand peaks in the winter heating season, and much lower demand during the shoulder and summer months. Figure 10 provides an illustration of Duke Energy's historical natural gas load from 2009 through September of 2014 - the blue shaded area depicts the range of historical values from January 2009 through September of 2014, while the bold blue line depicts just the year 2014 from January through September). Also shown is Duke Energy's forecasted load for the base case at five-year increments of 2020, 2025, 2030, and 2035 (see the yellow, purple, pink, and dotted gray lines, respectively).

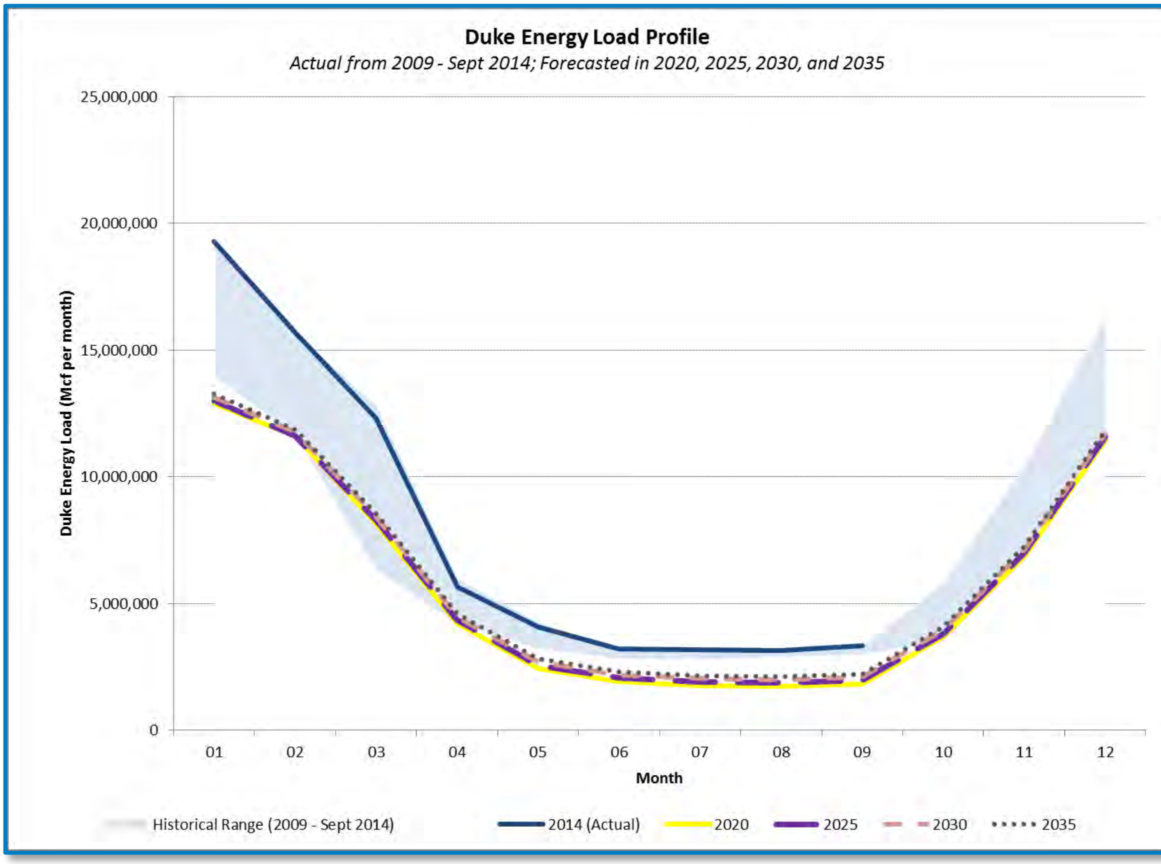


Figure 10: Duke Energy Load Profile, Historical and Projected

Source: Duke Energy, Historical Monthly Load, 2009-September 2014 and Duke Energy Spring 2014 Load Forecast

As the graphic in Figure 10 depicts, the base case forecast is projecting a lower amount of send out in future years as compared to the load observed over the last five years. The forecast follows the same seasonal load pattern seen in historical years, with higher winter demand and lower shoulder-month and summer-month demand. In recent years the natural gas load in January has been about four times higher than it has been in July. Despite the forecast years being somewhat lower than the current years, the forecast does project between 2% and 3% increases over each five-year period. The projected load shape depicted in Figure 10 is consistent with a trend in the industry toward increased efficiency of appliances and gas equipment, a trend that Duke Energy has observed in its own historic consumption data per discussions with the Duke Energy forecasting team. Weather impacts, in particular cold winters, impact the shape heavily when demand for gas to heat homes is high, which is depicted in the figure. As stated in the American Gas Association report "*Challenges* *and Opportunities in the Residential Natural Gas Market: results of the AGA Residential Market Share Survey*"[4] dated March 15, 2010, "Most companies expect market share to remain the same or to increase and expect use per customer to continue to decline as equipment and homes become more efficient." This conclusion supports the downward trend in the non-winter months in this same figure, absent an aggressive marketing plan to drive adoption of new gas appliances or equipment, such as NGV or other new technologies.

This graphic indicates that potential growth areas could target the lower load pattern time frames by targeting end-uses with different consumption profiles than those typically incorporated in the Duke Energy market today.

3.3 Existing Markets

Duke Energy currently serves three primary customer classes:

1. Residential, which includes 91% of their total customer base and about 40% of their total load,
2. Commercial, which includes 8% of their total customer base, and
3. Industrial, which includes about 0.3% of their total customer base.

An additional 0.4% of Duke Energy's customer base is made up of street lighting meters, public authority customers, and inter-departmental and company-use. The customer and load percentages presented here hold true across the combined Duke Energy Ohio and Duke Energy Kentucky customer base, as well as across each of these two separate service territories.[5]

As referenced above, the number of customers in each of these customer classes has remained relatively constant over the last five years, which is typical of an urban LDC environment. Despite a trend toward more customers moving from "full service" to "transportation" customers, the overall number of customers in both service territories and within all three customer classes has been relatively consistent since 2009.

Section 3.5, Business as Usual Demand Forecast, provides a more in-depth discussion of the business as usual case, which relies on assumptions consistent with this existing customer base.

3.4 New Markets

Based on discussions with the Duke Energy project team, Lummus Consultants investigated opportunities for Duke Energy to expand into key new markets for natural gas service. These new markets of interest were consistent with those referred to in Section 3.2.3, Natural Gas End-Uses, which include natural gas use in the transportation sector through expanded use of NGVs, particularly around the Interstate 71, 75, and 275 highways and interchanges; natural gas use as start-up fuel or primary fuel for central power generation, including coal-fired generating stations located along the Ohio river that are currently putting together emissions mitigation strategies to comply with evolving EPA regulations; natural gas use in coal-fired industrial boilers subject to similar Environmental Protection Agency (EPA) regulations; and, distributed generation opportunities to be powered with natural gas. These markets were identified as having the highest potential at this time. Duke Energy has recently been actively marketing to existing Duke Energy electric customers, commercial and industrial customers such as grocery stores in need of

[4] Source AGA EA 2010-02 March 16, 2010 Challenges and Opportunities in the Residential Natural Gas Market: Results of the AGA Residential Market Share Survey

[5] Duke Energy Kentucky has slightly more residential customers (92%) and less commercial customers (7%).

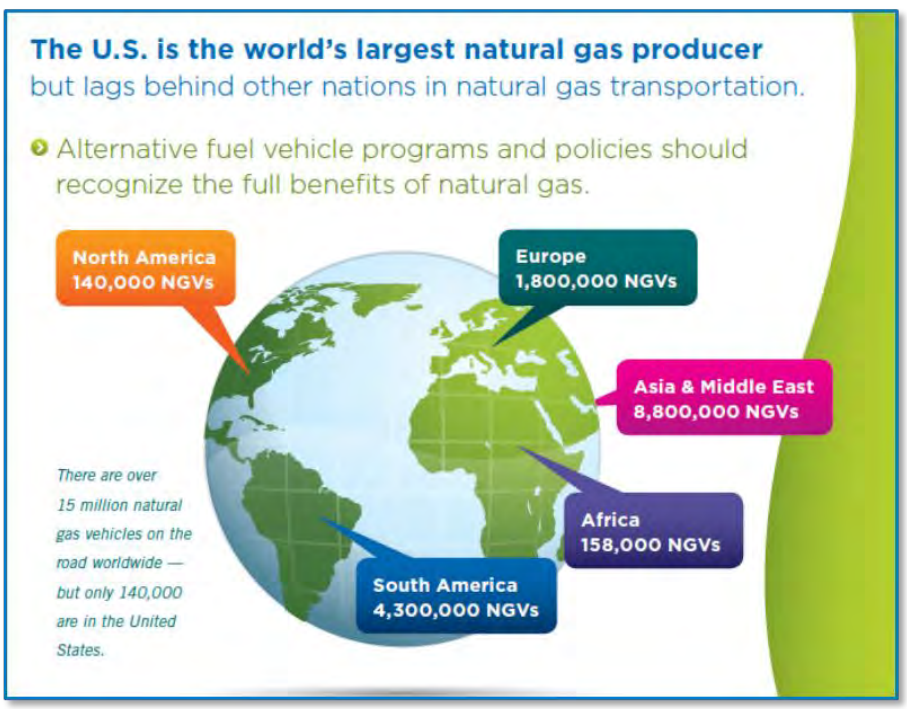
emergency backup, coal and oil conversions to natural gas for power generation, and NGV siting opportunities, in particular.

3.4.1 Natural Gas Vehicle Market

Federal information on the use of NGVs dates back to at least the 1980s. Recently there have been increased public and business interests in opportunities to move toward alternative fuel vehicles, which is somewhat driven by high oil price trends, low natural gas price trends, and more predominantly a shift in how the international community views carbon emissions. NGVs, electric vehicles, and other alternative fuel vehicles typically emit less carbon than typical gasoline or diesel-fueled fleets, and this difference, combined with tighter emissions standards and a focus on environmental sustainability, is causing many individual consumers and national and international companies to reevaluate their use of fuel in various transportation assets. Corporations like Anheuser-Busch and the United Parcel Service (UPS) are transitioning their vehicle fleets to more use of natural gas, motivated by the known emissions savings as well as the potential cost reductions.

Figure 11 below provides a global perspective on the penetration of NGVs as presented in the American Gas Association's "*2014 Playbook*" document.

Figure 11: Worldwide Natural Gas Vehicle Adoption6



Source: American Natural Gas Association, "2014 Playbook", page 70

Though North America has seen considerably lower levels of NGV adoption, as compared to other continents, there have been some large companies in the U.S. that have publicly stated their intentions to move toward natural gas and other alternative fuel vehicles. These companies include, for instance, UPS

[6] American Natural Gas Association, "*2014 Playbook*", page 70, available at http://www.aga.org/our-issues/playbook/Pages/default.aspx .

and Anheuser-Busch (A-B), both of which operate large commercial and over-the-road truck fleets. A recent Forbes article described Anheuser-Busch's move toward using NGVs at its Houston brewery:

> "*It's significant that A-B feels comfortable swapping for an entire fleet that runs on CNG. The intention of shifting to natgas, says James Sembrot, A-B's senior transportation director, is to reduce carbon emissions and fuel costs, while doing something green(ish). The Houston brewery is among the biggest of the 14 that A-B operates nationwide*."[7]

Likewise, UPS has for a long time been using alternative-fuel vehicles. An excerpt from the American Natural Gas Association website describes their commitment:

> *"UPS, the world's largest package-delivery and logistics company, operates one of the nation's largest NGV fleets. Its iconic brown delivery trucks are instantly recognizable, but what many people don't know is that UPS is truly committed to the environment. The company has used alternative-fuel vehicles including NGVs to transport packages for years, and in 2014 most of the new tractor-trailers UPS puts on the road will be powered by natural gas."*[8]

3.4.1.1 Historical NGV Demand Growth

The following table describes natural gas vehicle-related data in the seven states that are hereafter referred to as "top adopting states". These seven states, California, New York, Texas, Oklahoma, Utah, Arizona, and Georgia, represent the top five states by number of natural gas fueling stations open, as well as the top five states by percentage share of the total U.S. natural gas delivered for vehicle fuel end-use. Three of these states, California, New York, and Texas, are in the top five according to both metrics.

Table 3: Top Adopting States for Natural Gas Vehicles

Top Five States…	…by Number of Natural Gas Vehicle Fueling Stations[9]	Rank	…by Share of Total US Natural Gas Delivered for Vehicle Fuel End Use[10]	Rank
California	328	1	48.91%	1
New York	112	2	12.9%	2
Texas	101	3	7.35%	3
Oklahoma	101	3	0.85%	16
Utah	95	5	0.97%	12
Arizona	40	9	5.71%	4
Georgia	30	14	3.66%	5
United States Total	**1,510**		**100%**	

Source: (1) U.S Department of Energy, Energy Efficiency and Renewable Energy, "Alternative Fuels Data Center"; (2) U.S. Energy Information Administration, Natural Gas Information for Vehicle Fuel End-Use

[7] Forbes, "*Budweiser puts its Diesel Trucks To Pasture, Switches to Natural Gas*", published on September 9, 2014, available at http://www.forbes.com/sites/christopherhelman/2014/09/09/budweiser-puts-its-diesel-trucks-out-to-pasture-switches-to-natural-gas/

[8] American Natural Gas Association, "*Natural Gas Delivers for America*", posted march 18, 2014, available at http://anga.us/blog/2014/3/18/natural-gas-delivers-for-america

[9] Data as of August 2014. Source: US Department of Energy - Energy Efficiency and Renewable Energy, "Alternative Fuels Data Center", http://www.afdc.energy.gov/fuels/natural_gas_locations.html; accessed in August 2014.

[10] Data as of 2012. Source: US Energy Information Administration, Natural Gas Information for Vehicle Fuel End-Use, http://www.eia.gov/naturalgas/, accessed in August 2014

In looking at California and Texas, Table 4 provides data to describe the number and timing of compressed natural gas (CNG) and liquefied natural gas (LNG) stations that opened in three of those states' major cities. Also described is the CNG and LNG station count information in Columbus, Ohio, and Louisville, Kentucky.

Table 4: CNG and LNG Stations, by Major City

City	Metropolitan Population *(Census[11])*	Number of CNG and LNG Stations Opened Annually[12]						Total Open (as of 2014)
		2010	2011	2012	2013	2014[13]	Total (2010-2014)	
Large Cities in Top Adopting States								
Houston, TX	6 M (metro)	1	0	3	4	2	**10**	**13**
Dallas/Fort Worth, TX	6 M (metro)	0	1	6	5	3	**15**	**24**
Los Angeles, CA	13 M (metro)	0	4	1	0	4	**9**	**30**
Ohio and Kentucky Cities								
Columbus, OH	2 M (metro)	0	1	1	1	2	**5**	**6**
Louisville, KY	1.3 M (metro)	0	0	1	0	0	**1**	**1**

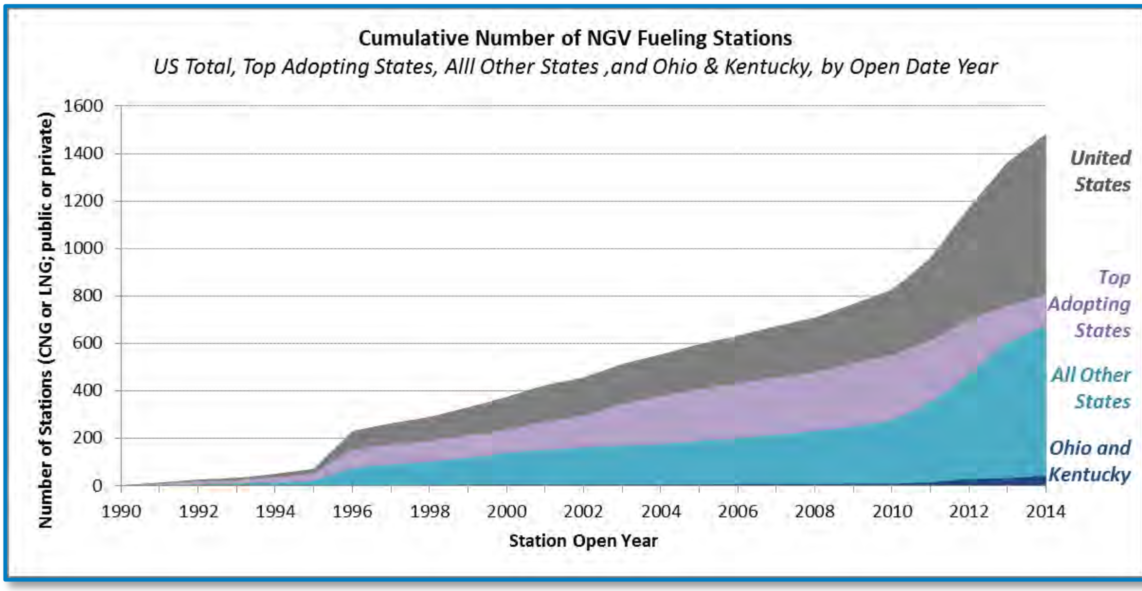
Sources: (1) U.S. Census Data from 2010 to 2014; (2) U.S. Department of Energy, Energy Efficiency and Renewable Energy, "Alternative Fuels Data Center"

For comparative purposes, as of the 2010 Census the Cincinnati, Ohio, metropolitan area, which encompasses a large part of Duke Energy's natural gas service territory, had a population of approximately 2 million people, similar in size to the metropolitan area of Columbus, Ohio, as stated above.

Figures 12 and 13 below provide additional illustrations to describe trends in the growth of natural gas fueling stations as well as natural gas consumption for vehicle end-uses over the past 15 years.

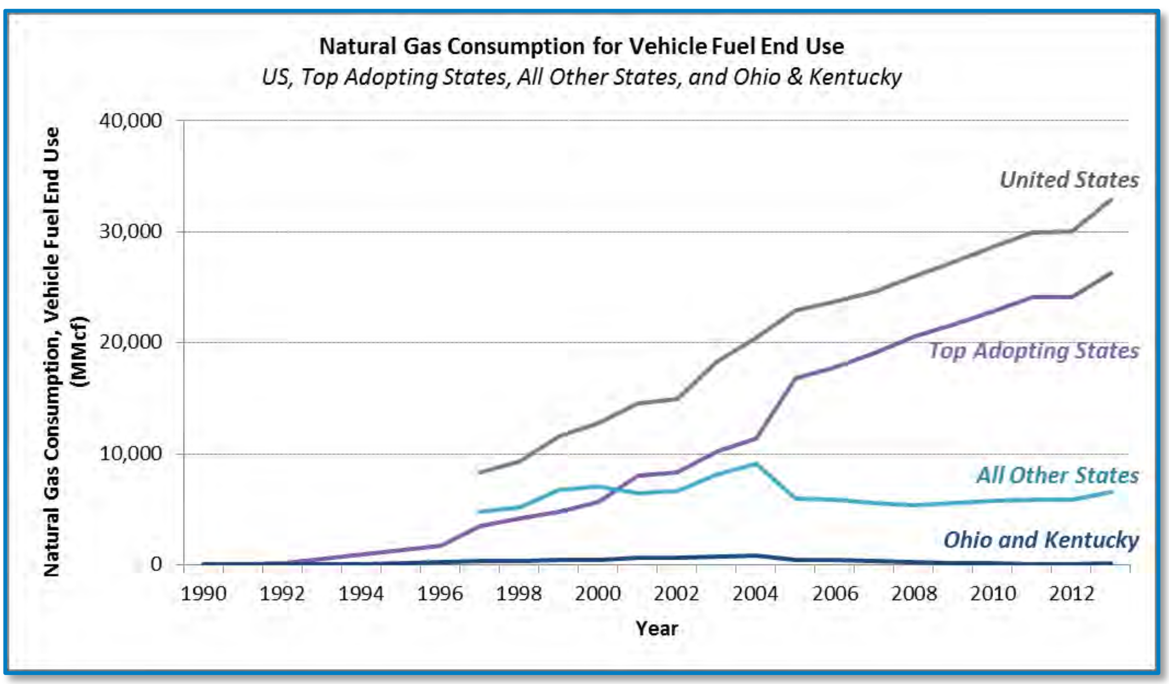
[11] Census data ranges from 2010 to 2014 sources.
[12] US Department of Energy, Energy Efficiency and Renewable Energy, "Alternative Fuels Data Center", http://www.afdc.energy.gov/fuels/natural_gas_locations.html; accessed in August 2014.
[13] As of August 2014 research.

Figure 12: Cumulative Number of NGV Fueling Stations - United States



Source: U.S Department of Energy, Energy Efficiency and Renewable Energy, "Alternative Fuels Data Center"

Figure 13: Natural Gas Consumption for Vehicle Fuel End Use - United States

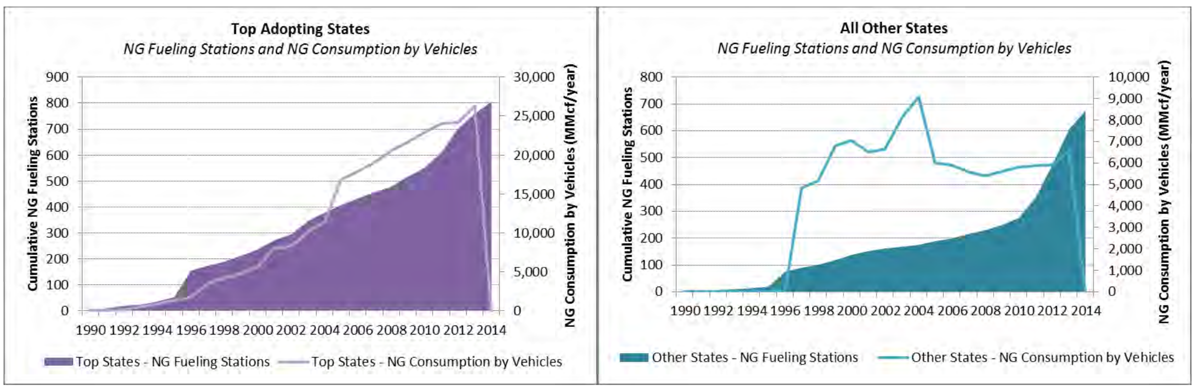


Source: U.S. Energy Information Administration, Natural Gas Information for Vehicle Fuel End-Use

In both of the graphics on the previous page, the purple area and purple trend line describe historical data for the seven "top adopting states" defined above. These graphics show relatively consistent trends in new fueling stations and consumption of natural gas, indicating that the markets in these states may be more mature than other states. The light blue areas in Figure 12 and the light blue trend line in Figure 13 describe the historical data from the other 43 states in the U.S. In Figure 12, the time frame from 2011 through 2014 shows a more rapid increase in the number of CNG and LNG stations in all other states, whereas the natural gas consumption trends in Figure 13 show a leveling off of consumption in all other states between 2005 and 2012.

Figure 14, below, overlays these trends together. Again, there is a consistency in the trends in the left graphic for top adopting states, whereas there is more variability in the data for all other states in the right graphic, indicating that the NGV markets may still be maturing there.

Figure 14: Natural Gas Station and Consumption, Top Adopting States versus All Other States



There are currently a small number of NGV fueling stations operating in Ohio and Kentucky. Most of them are located around Columbus, Ohio, and the northeastern part of Ohio, as well as around the northwestern border of Kentucky. There are also five stations that fall within Duke Energy's service territory, all of which are listed in Table 5. In addition to these five there are an additional two stations in the City of Hamilton that are served by a neighboring gas utility.

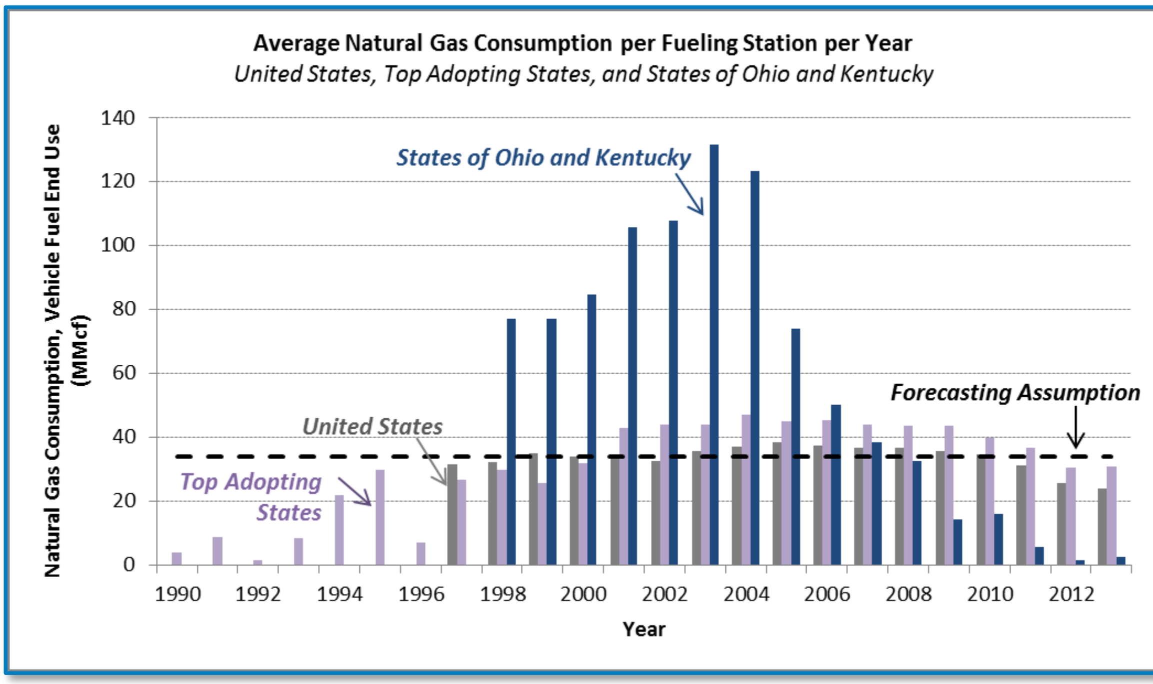
Table 5: Existing Natural Gas Fueling Stations in Duke Energy's Service Territory

Fuel Type Code	Station Name	Street Address	City	State	Zip code	Customer Accessibility
CNG	Rumpke *	3700 Struble Rd	Colerain	OH	45251	Private
LNG	Clean Energy - Franklin Pilot #9 *	6830 Franklin-Lebanon Rd	Franklin	OH	45005	Public - Card key at all times
CNG	Home City Ice †	5709 State Route 128	Cleves	OH	45002	Private
CNG	Duke Energy †	153 West 19th St.	Covington	KY	41014	Private
CNG	City of Cincinnati †	4747 Spring Grove Ave	Cincinnati	OH	45232	Private - Government only

** Source: US Department of Energy, Energy Efficiency and Renewable Energy, "Alternative Fuels Data Center"*
† Source: Duke Energy

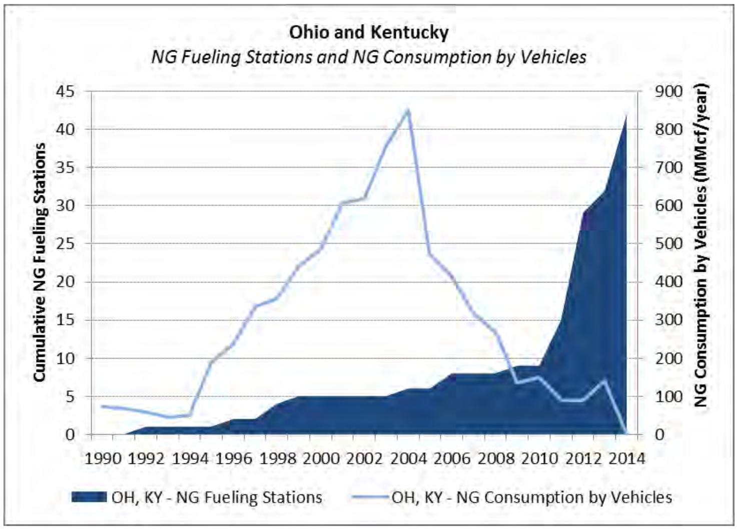
Figure 15 provides a graphical representation of the calculated fuel consumption per station for all of the U.S., for the Top Adopting States, and for the states of Ohio and Kentucky taken together. The data plotted in this graphic is simply calculated using the total amount of natural gas delivered for vehicle use, divided by the number of fueling stations. U.S. and Top Adopting States information average around 34 MMcf per station, annually. This assumption is used later in projecting the demand potential in Duke Energy's service territory from this new market. Of note is that Ohio and Kentucky saw a dramatic rise in natural gas consumption for vehicle use in 1998 through 2003; versus a constant number of natural gas fueling stations over that time period, which results in the steady rise in the MMcf/station metric in those years. Conversely, there was a sharp decrease in natural gas consumption by vehicles from 2004 through 2012, while the number of fueling stations rose sharply from 2011-2014, causing the MMcf/station metric to decrease over 2004-2013, most extensively in 2011 and 2012. Figure 16 provides a more in-depth look at these trends, for comparative purposes.

Figure 15: Average Natural Gas Consumption per Fueling Station



Source: (1) U.S. Department of Energy, Energy Efficiency and Renewable Energy, "Alternative Fuels Data Center";
(2) U.S. Energy Information Administration, Natural Gas Information for Vehicle Fuel End-Use

Figure 16: NG Fueling Stations and NG Consumption by Vehicles



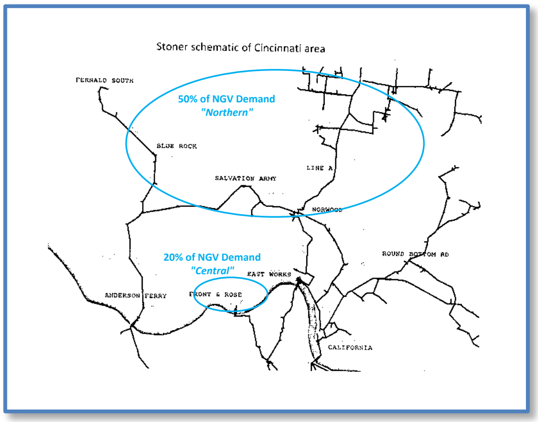
Source: (1) U.S. Department of Energy, Energy Efficiency and Renewable Energy, "Alternative Fuels Data Center"; (2) U.S. Energy Information Administration, Natural Gas Information for Vehicle Fuel End-Use

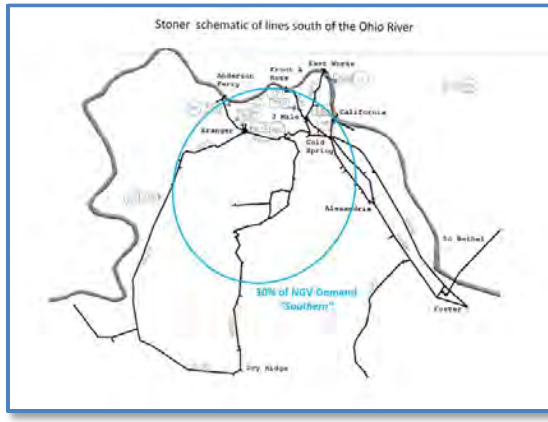
3.4.1.2 Potential for Future NGV Demand Growth

Based on the information above, this section provides demand forecast cases that describe the number of forecasted natural gas fueling stations, and associated annual consumption and peak-hour flows, that might materialize in the Duke Energy service territory over the next twenty years, in five-year forecast segments.

Locations on the Duke Energy system that would make the best candidates for NGV charging stations are located around interstates 71, 75, and 275, particularly where these three interstate highways intersect. There are a number of trucking stations and truck maintenance and rental facilities positioned around these highways and around their interchanges, such as for instance Pilot Flying J locations, TravelCenters of America stops, and Ryder maintenance facilities. In addition to facilities geared toward the trucking industry, there are also business locations for UPS, PepsiCo, and Anheuser-Busch around these same highways and in the downtown Cincinnati area. Each of these companies have corporate fleets and have made public commitments to reducing greenhouse gas emissions and fuel costs, potentially through migrating their trucking fleets to NGVs and/or electric or other alternative fuel vehicles. About 30% of these current locations are positioned north of and along I-71/75 south of Cincinnati, about 50% of the locations are positioned north of Cincinnati along I-71 and I-75, around where I-275 intersects both of these interstates and about 20% of the locations are in downtown Cincinnati. These areas are circled in Figure 17, for reference.

Figure 17: Natural Gas Vehicle Charging Station Demand Locations





A key factor that will impact Duke Energy's entry into the NGV market is the point at which the system is free of propane. NGV equipment is very sensitive to the presence of propane as propane can cause operational issues. Each of the three general locations mentioned above (southwest, northeast, central) are partially impacted by the operation of Duke Energy's propane-air facilities. Section 3.6, High Demand Forecast with Growth in New Markets, provides additional details of how the presence of propane is expected to impact Duke Energy's growth into this new market.

As a means of bracketing the potential for NGV adoption and the resulting changes in natural gas demand that might materialize, Lummus Consultants defined a set of three "NGV adoption cases". The medium and rapid adoption cases both assume that the Duke Energy system will be free of propane by 2020, as might be possible based on input from Lummus Consultants' system improvement planning team. Prior to 2020, both of these cases assume a certain amount of growth into the NGV market in areas that are currently free of propane, which is limited. In general, the rapid adoption case assumes more adoption of NGVs than the medium adoption case and at a faster rate as well. By contrast, the slower adoption case assumes less adoption than the medium case and at a slower rate. It also assumes that the system is not free of propane until 2025, five years delayed from the assumption in both the medium and rapid adoption cases.

Table 6: NGV Forecast, Medium Adoption Case

	2015	2020	2025	2030	2035
Natural Gas Stations (Incremental Additions)	0	2	5	5	5
Natural Gas Stations (Cumulative)	0	2	7	12	17
Annual Growth Rate in Stations (%)			50%	14%	8%
Natural Gas Deliveries (MMcf annually)[14]	0	68	238	408	578
Peak-Hour Flow (Mcfh)	0	13	44	75	107

The "medium adoption case" described in Table 6, above, assumes limited growth in the NGV market before 2020 due to the limitation of propane-air in the Duke Energy system; stations would only be added in propane-free areas prior to 2020, such as around interstate 71 and 75, located south of Cincinnati in

[14] Based on an assumption of 34 MMcf/station, annually. See historical trending supporting this assumption in Section 3.4.1.1, Historical NGV Demand Growth.

northern Kentucky. The growth rate after 2020 is assumed to be consistent with the growth rate in stations observed in Columbus, Ohio over the past five years, as Columbus is similar in size to Cincinnati.

Table 7: NGV Forecast, Rapid Adoption Case

	2015	2020	2025	2030	2035
Natural Gas Stations (Incremental Additions)	0	5	13	15	20
Natural Gas Stations (Cumulative)	0	5	18	33	53
Annual Growth Rate in Stations (%)			52%	17%	12%
Natural Gas Deliveries (MMcf annually)[15]	0	136	476	816	1,156
Peak-Hour Flow (Mcfh)	0	31	113	207	332

The "rapid adoption case" described in Table 7 assumes limited growth in the NGV market before 2020 due to the same propane-air limitations as in the medium adoption case. Again, stations are only assumed to be added in propane-free areas prior to 2020. After 2020, the NGV rapid adoption case assumes twice as many stations are opened as compared to the medium adoption case, an aggressive rate of growth more similar to the station growth rates in Houston, Texas over the past five years.

Table 8: NGV Forecast, Slower Adoption Case

	2015	2020	2025	2030	2035
Natural Gas Stations (Incremental Additions)	0	1	1	2	3
Natural Gas Stations (Cumulative)	0	1	2	4	7
Annual Growth Rate in Stations (%)			20%	20%	15%
Natural Gas Deliveries (MMcf annually)[16]	0	34	68	136	238
Peak-Hour Flow (Mcfh)	0	6	13	25	44

The "slower adoption case" described in Table 8, above, assumes a delayed implementation of propane elimination, thus there is limited growth in the NGV market before 2025. Stations would only be added in propane-free areas prior to 2025, which is a five-year delay as compared to the medium and high adoption cases. The number of stations opened is also projected to be about half of the rate of the medium adoption case, more similar with the station growth rate in Louisville, Kentucky over the past five years.

3.4.2 Electric Power Generation Market

Natural gas demand from power plants is a potential demand source in both of Duke Energy's natural gas networks. Both natural gas-fueled and coal-fueled power plants are potential sources of current and future natural gas demand. Duke Ohio currently supplies natural gas to the coal-fired William H. Zimmer Power Station (Zimmer) along the Ohio River. According to Duke Energy representatives, propane air is not expected to cause operational issues at the large coal-fueled power plants along the Ohio River. By contract, small amounts of propane can be tolerated in gas boilers, but would cause operational concerns in gas turbines at lower levels.

3.4.2.1 Power Plant Screening

Operating coal plants can use natural gas for start-up and in their auxiliary boilers. Recently many coal fired power plants have converted their start up and auxiliary boiler fuel to natural gas from fuel oil as

[15] Ibid.
[16] Ibid.

cost saving and emissions reduction measures. Retiring coal fired power plants have the potential to be repowered with natural gas or replaced with new natural gas combined cycle plants, which would trigger additional demand for natural gas in future years.

All coal fired power plants in the Duke Energy Ohio and Kentucky service areas were screened to assess the potential for natural gas sales. These include the following generating stations that are more than 100 MW in size:

- Miami Fort
- Stuart
- Zimmer
- Killen
- East Bend
- Beckjord
- Hutchings

Beckjord and Hutchings will both be retired due to the cost-prohibitive upgrades and retrofits that would be required for these units to comply with the EPA Utility Maximum Achievable Control Technology (MACT) rule. The current plant owners (Duke Energy and Dayton Power and Light, respectively) are not planning on repowering these facilities with natural gas, nor are they planning on directly replacing the facilities with new natural gas combined cycles plants.

Duke Energy has not had any discussions about supplying natural gas to Killen or East Bend, both of which use No. 2 fuel oil for start-up. Because Duke Energy has not had gas supply discussions with these plants, Lummus Consultants has not included them in the new markets demand forecast, however further analysis of the supply and demand projections for electricity in the area would provide a better understanding of whether these sites might be utilized in the future.

The three major coal power plants in the Duke Energy Ohio and Kentucky natural gas service areas that are considered to be potential Duke Energy natural gas consumers are located along the Ohio River in southeast Ohio. These coal facilities include Miami Fort in the west, and Beckjord, Stuart, and Zimmer in the east. Duke Energy recently agreed to sell its non-regulated Midwest generation to Dynergy, which includes these facilities. An assessment of the potential is provided below for each facility.

- *Miami Fort* - The Miami Fort facility consists of two operating coal fired units and four operating combustion turbine units that burn distillate fuel oil. This site also contains five retired units (three retired coal-fired units and two retired combustion turbine units). The two operational coal-fired units have a combined capacity of 1,020 MW and the four combustion turbine units have a combined winter capacity of 80 MW for a grand total of 1,100 MW at this facility. The recent capacity factors for the coal fired units and the fuel oil fired units are in the 65-85% range and the 0% range, respectively. Operating all lighters for one unit would consume 480 to 800 Mcfh of natural gas. If all lighters were operating for Units 6, 7, and 8, 2,000 Mcfh would be consumed. Total potential natural gas demand for the site would be 13,000 Mcfh, including the combustion turbine units. Miami Fort is expected to utilize gas for a portion of their lighters. A larger natural gas line to the plant would be required to serve a significant portion of the potential demand. Duke Energy projects a demand of 2,000 Mcfh for Miami Fort, consistent with lighters for Units 6, 7, and 8 utilizing gas.

- *Stuart* - The J M Stuart facility is currently co-owned by AEP, Dayton Power and Light, and Duke Energy and it consists of four coal-fired units and four distillate fuel oil-fired internal combustion engines with a combined nameplate capacity of 2,452 MW. The recent capacity factors for this plant are in the 50-70% range, but are most recently at the lower end of that range.

Lighters for a single unit would consume 960 Mcfh and four units would consume 3,800 Mcfh. Co-firing with natural gas is possible and since an auxiliary boiler would require 230 Mcfh, a total of 1,200 Mcfh would be required to operate a single unit and the auxiliary boiler. A larger natural gas line to the plant would be required to serve a significant portion of the potential demand. Stuart is expected to utilize gas for a portion of their lighters and possibly the auxiliary boiler. Duke Energy expects a future demand for natural gas of 408 Mcfh for Stuart, which has been reflected in Lummus Consultants' new markets demand forecast.

- *Zimmer* - The W H Zimmer facility consists of a single 1,300 MW coal fired unit that came online in March of 1991. The recent capacity factors for that unit are in the 50-80% range. Their auxiliary boilers are now operated only by natural gas. Duke Energy currently supplies Zimmer with some natural gas, with loads as high as 1,300 Mcfh. Operating one lighter set would require 63 to 125 Mcfh. Zimmer is expected to utilize gas for at least a portion of their lighter sets going forward. A larger natural gas line to the plant would be required to serve a significant portion of the potential demand. Duke Energy projects a demand of 2,400 Mcfh for Zimmer.

Another potential opportunity for future gas demand that was considered but that is not included in the projection is an NTE Energy project. In Middletown, Ohio, along Cincinnati Dayton Road, between Todhunter Road and Oxford State Road, just east of AK Steel, NTE Energy plans to build a gas-fired power plant that would use approximately 3,300 Mcfh of natural gas. NTE Energy, however, is in discussions with two gas transportation pipeline companies that cross their property. According to the Duke Energy team, the likelihood of Duke Energy serving that demand is low due to the competition from these companies.

3.4.2.2 Coal-Conversion Industrial Boiler Screening

Smaller, industrial coal power plants in the Duke Energy Ohio and Duke Energy Kentucky service areas include:

- Hamilton
- Miller Coors Brewery
- Procter & Gamble Ivorydale
- Wausau Paper
- Mississippi Lime
- Rock-Tenn

Since Duke Energy has not had any discussions with Hamilton or Miller Coors Brewery about supplying natural gas, Lummus Consultants has not included either of these two facilities in the new markets demand forecast. The smaller, industrial coal fired power plants in the Duke Ohio and Duke Kentucky gas service areas that Duke Energy has had discussions with are Procter & Gamble Ivorydale, Wausau Paper, Mississippi Lime, and Rock-Tenn. Rock-Tenn announced in October of 2014 that the paperboard mill in Cincinnati would be closing by year-end. Natural gas demand from these three remaining facilities has been incorporated in the new markets demand forecast.

3.4.2.3 Distributed Power Generation Opportunities

Natural gas demand from distributed generation is a potential demand source in the Duke Ohio and Duke Kentucky gas distribution network. The primary sources of such demand are: (1) small power generators that use natural gas fuel, such as natural gas reciprocating engines and (2) stationary power distributed generation fuel cells that use natural gas as a fuel to produce hydrogen.

Natural Gas Engines

According to the United States Energy information Administration (EIA)[17], in 2012, Duke Energy Ohio had 3.4 MW of internal combustion or reciprocating engine distributed generation, while Duke Energy Kentucky had 0 MW.

Owen Electric Cooperative conducted a feasibility study for up to 2 MW of gas-fired reciprocating engine(s), equivalent to approximately 16 Mcfh, or 8 Mcfh per 1 MW engine, in southern Campbell County. This inquiry could become an opportunity in the future if the project develops and this potential opportunity could be supported by Duke Energy through the implementation of any of the eight expansion scenarios presented in this Gas System Master Plan. Such a level of future demand is consistent with the current levels of internal combustion or reciprocating engine distributed generation in the Duke Energy Ohio and Kentucky service areas. Note, natural gas engines are assumed to have interruptible natural gas fuel supply contracts.

Fuel Cells

Stationary power distributed generation fuel cells using natural gas as an input are being developed by many companies, including Bloom Energy. Bloom Energy, for example, has two solid oxide fuel cell modules, a 200 kW module that uses 1.29 MCFH and a 100 kW module that uses 0.644 MCFH. Ohio is at the forefront of fuel cell manufacturing and research and development (R&D); however, neither Kentucky nor Ohio has installed a significant amount of stationary power distributed generation fuel cells.

Stationary power distributed generation fuel cells are assumed to have interruptible natural gas fuel supply contracts, as the commercial entities who would be the main customers would also be connected to the grid and thus the premium for a firm natural gas supply would not be economical. As discussed in the next section, the "new markets" demand forecast does not assume fuel cell adoption in future years.

3.4.2.4 Potential for Future Gas Demand from Electric Generation Facilities

The following table summarizes the expected future gas demand from central power plants, coal-conversion industrial boilers, and distributed generation based on input from Duke Energy. Lummus Consultants finds these projections to be reasonable. The demand from all of these power generation sources is assumed to be predominantly interruptible demand, with only a small portion of firm natural gas to the Zimmer power plant.

Table 9: Electric Power Generation Forecast

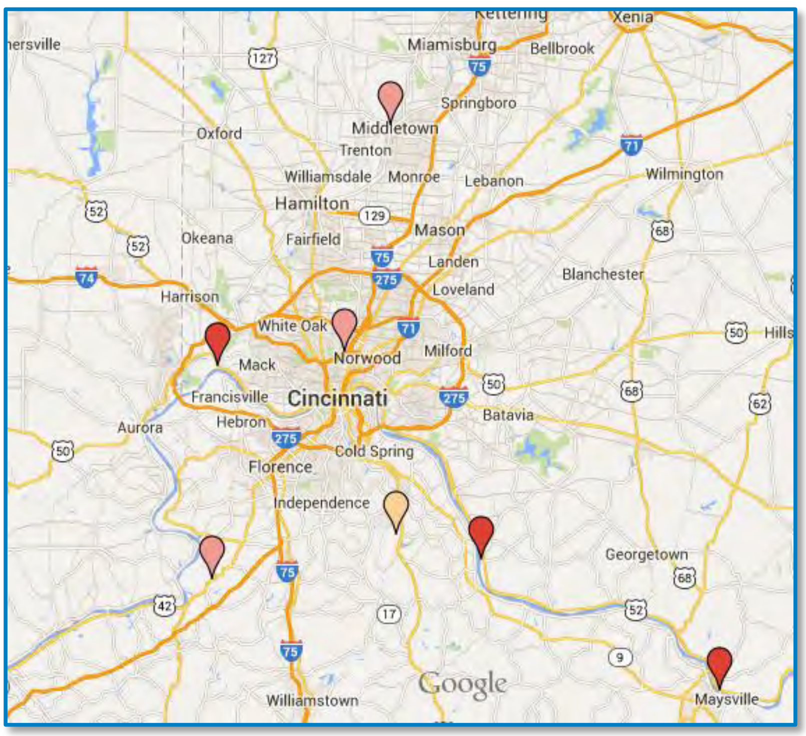
	Total Natural Gas Demand *(Exiting and New)*	New Markets Demand (Mcfh)	Start Year	Notes
Power Plants				
Miami Fort	2,000 Mcfh	2,000	2015	
Stuart	408 Mcfh	408	2015	
Zimmer	2,400 Mcfh	2,400	2015	62-125 Mcfh of this demand is requested to be firm

[17] Electric power sales, revenue, and energy efficiency Form EIA-861 detailed data files, released October 29, 2013

	Total Natural Gas Demand *(Exiting and New)*	New Markets Demand (Mcfh)	Start Year	Notes
Coal-Conversion Industrial Boilers				
Procter & Gamble	152 Mcfh	0	2016	Already included in model
Mississippi Lime	118 Mcfh[18]	118	2017	
Wausau Paper	125 Mcfh	75	2017	Increase from current 50 MCFH
Distributed Generation				
Owen Electric DG	16 Mcfh	16	about 2017	

The table does not assume any future demand from new combined cycle central station power plants or coal repowering projects, as no such projects are very far along in development in the service area. The location of each of these stations is shown in the map figure below, including the three power plants (red balloons), three industrial boilers (pink balloons), and one distributed generation site (orange balloon).

Figure 18: Electric Power Generation Demand Locations



3.5 Business as Usual Demand Forecast

Lummus Consultants reviewed the forecasting methodology document entitled "*Gas and Natural Gas Demand Forecasts for Gas Distribution Companies serving more than Fifteen thousand Customers*", which provided a description of Duke Energy's forecasting methodology. The methodology relies on a national economic forecast, provided by Moody's, as well as a more-detailed service area economic forecast (also by Moody's) that provides employment, income, production, and population data on a

[18] Estimated from annual demand using a 70% annual average load factor.

projected basis. Lummus Consultants was not privy to either of these forecasts due to an existing confidentiality agreement between Duke Energy and Moody's that covers these types of files.

Forecasts are developed by system (Ohio, Kentucky) at the customer segment level (Residential, Commercial, Industrial, etc.). The forecast for each of these sectors is dependent on the following factors:

- Residential - The residential forecast is impacted by the number of natural gas customers (expressed as a percentage of Duke Energy electric customers), natural gas prices, household income, and heating degree days.
- Commercial - The commercial forecast is made up of two forecasts, a firm forecast and an interruptible forecast. Firm commercial gas is impacted by the same factors that drive the residential sector (households, heating degree days, and average gas prices). Interruptible demand is forecasted based on a relationship similar to firm commercial deliveries.
- Industrial - Industrial demand is also split into firm sales and interruptible sales. The firm sales are dependent upon manufacturing gross product, heating degree days, and average gas prices, and again the interruptible forecast is developed through a relationship to the firm forecast.
- Other - In addition to the three sectors above, Duke Energy forecasts include projections for Other Public Authority Gas Deliveries, Street Lighting, Inter-Departmental Gas Sales, and finally, Company-Use Sales.

Based on discussions with the Duke Energy forecasting team, the forecast is as granular as these major sectors, a more detailed zip-code, or delivery-node-based forecast is not available. Lummus Consultants was told that none of the potential 'new market demand' was considered in the business-as-usual base case.

The resulting peak forecasts are presented below in graphical format. The peak forecast anticipates varying levels of certainty the system will exceed its total peak or its firm peak. Note, the modeling and planning work covered in the remainder of this report considers the 1% probability of exceeding firm peak as the criteria against which to plan. The trend in the forecast in Figure 19 is very flat on a going-forward basis, with an annual growth rate of roughly one half of a percent.

In order to better understand the underlying efficiency assumptions inherent in the base case forecast, the projected usage data was divided by the projection for number of customers. The results of that analysis are plotted in Figure 20. The trend in that graphic shows that, historically, customers use more natural gas in the winter months and about 25% of that amount in summer months. The base case forecast shows a down step in this efficiency, with a similar seasonal trend and relationship, but with lower peaks and lower valleys as well.

Figure 19: Duke Energy, Natural Gas Peak Forecast, Base Case

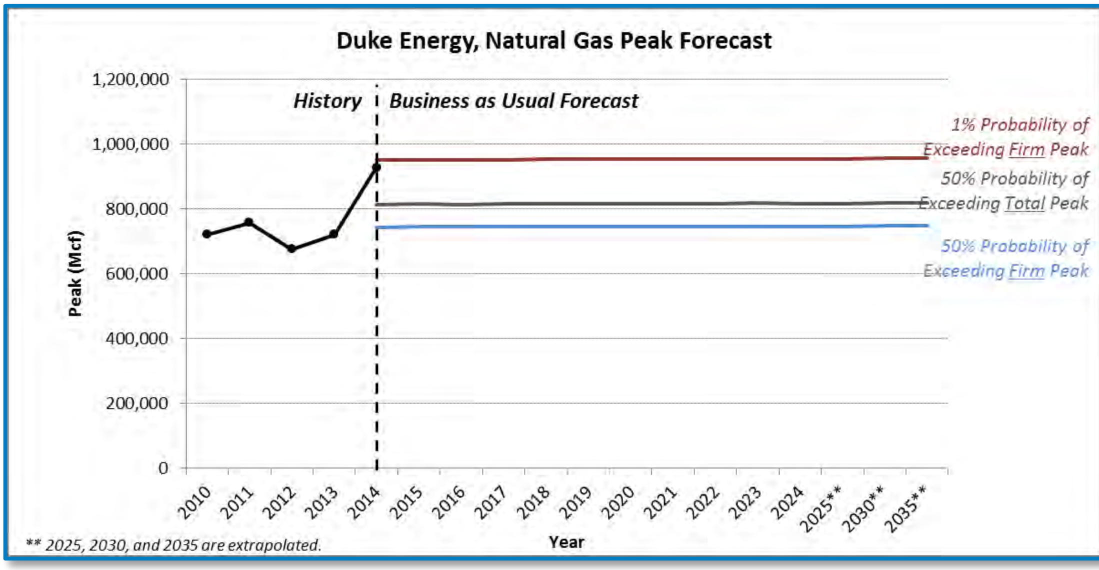
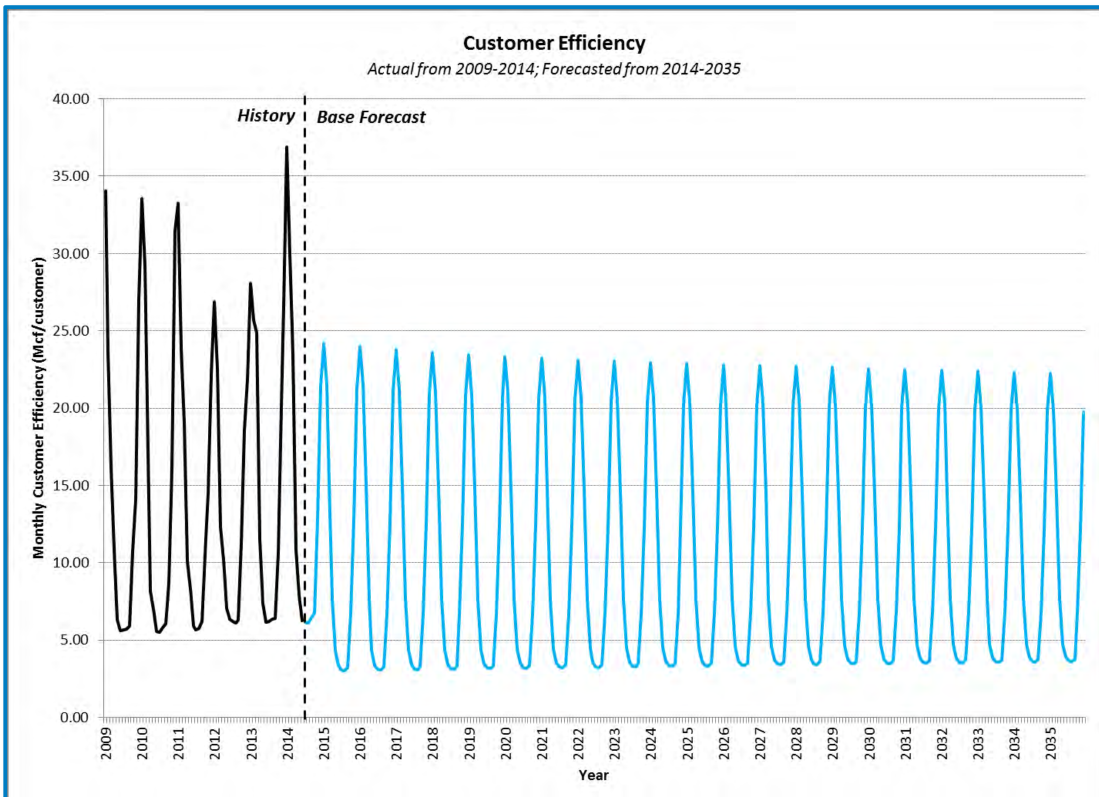


Figure 20: Duke Energy, Natural Gas Use per Customer, Base Case



3.6 High Demand Forecast, with Growth in New Markets

In order to incorporate the potential demand for natural gas in new markets within the context of Duke Energy's firm peak forecast, with a 1% probability of exceeding that forecast, Lummus Consultants first had to determine which new demand would materialize as "firm demand" versus "interruptible demand". Equally important would be the location of the potential new demand and whether (a) it would be subject to propane events and (b) whether it would be sensitive to propane in the system.

The following table provides a summary of all of these assumptions for the four market segments discussed earlier in this Chapter.

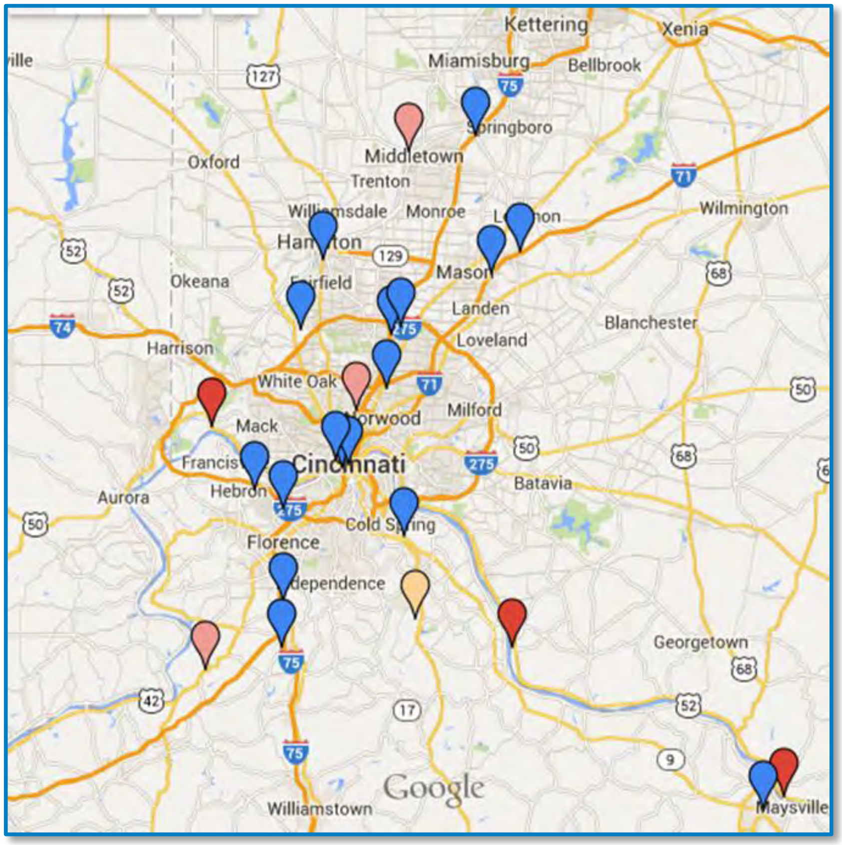
Table 10: New Markets Assumptions

New Natural Gas Market	Sub-market	Firm or Interruptible Demand	Subject to Propane?	Sensitive to Propane?
Natural Gas Vehicles	*Northeast*	Firm	No	Yes
	Central	Firm	Yes	Yes
	Southwest	Firm	Yes	Yes
Power Generation	*Central Power Stations*	Interruptible	No	No
	Coal-Conversion Industrial Boilers	Interruptible	Yes	At high saturation
	Distributed Generation	Interruptible	No	Yes

This table provides the assumptions that were used in determining how to layer the various growth potentials on top of the business as usual case, discussed in Section 3.5.

The map in Figure 21 depicts where the demand growth areas are located - again, dark red markers indicate central power stations, pink markers indicate coal-fired industrial boilers, and the orange marker indicates the distributed generation opportunity - to this figure blue markers have also been added to indicate expected NGV fueling locations.

Figure 21: New Market Demand Locations



The three figures below provide transmission-level and distribution-level images of the impact of propane in the system when the Erlanger and East Works propane plants are operating. Blue lines indicate propane free areas whereas the red lines indicate propane in the system.

Figure 22: Propane Presence in Duke Energy Transmission System

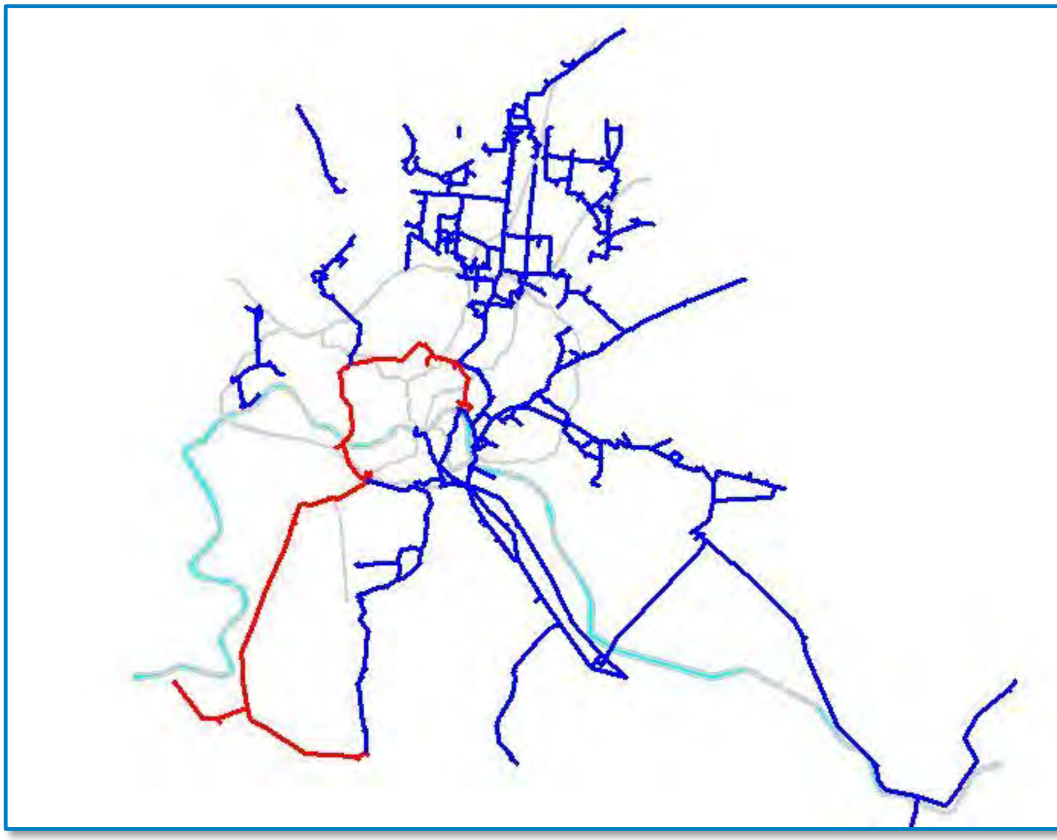


Figure 23: Propane Presence in Duke Energy Distribution System, Propane Plants Operating, Ohio Detail

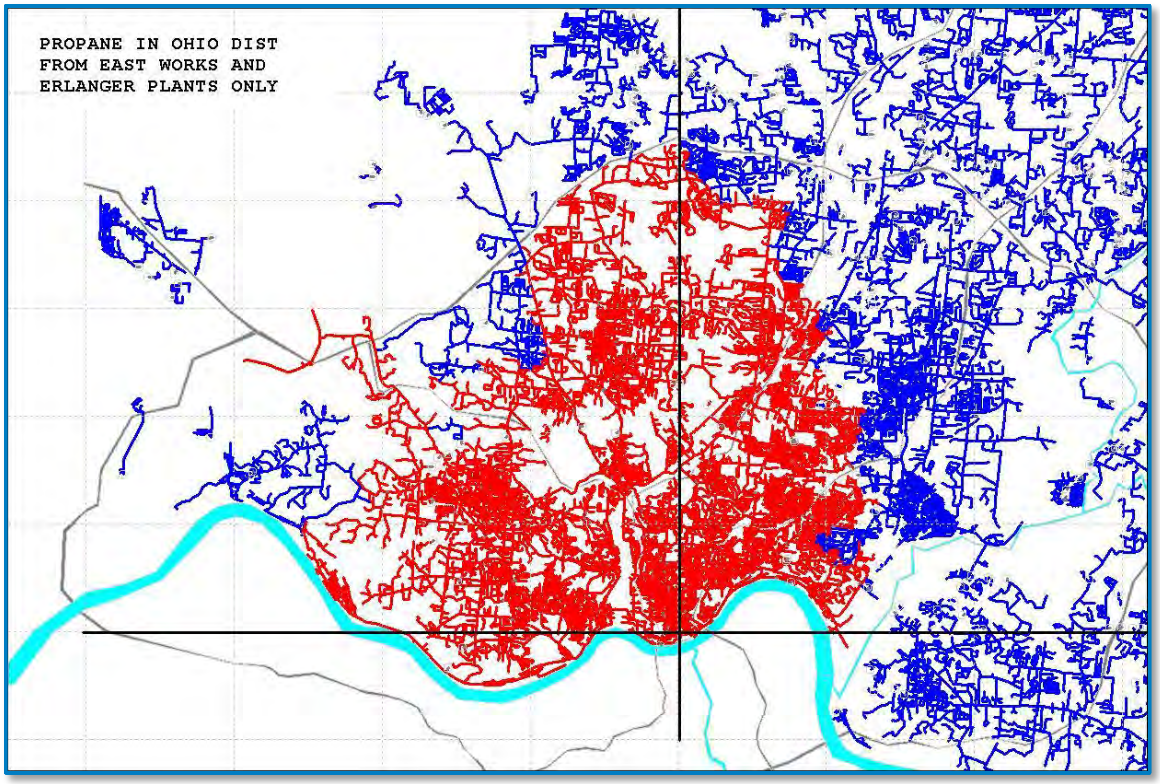
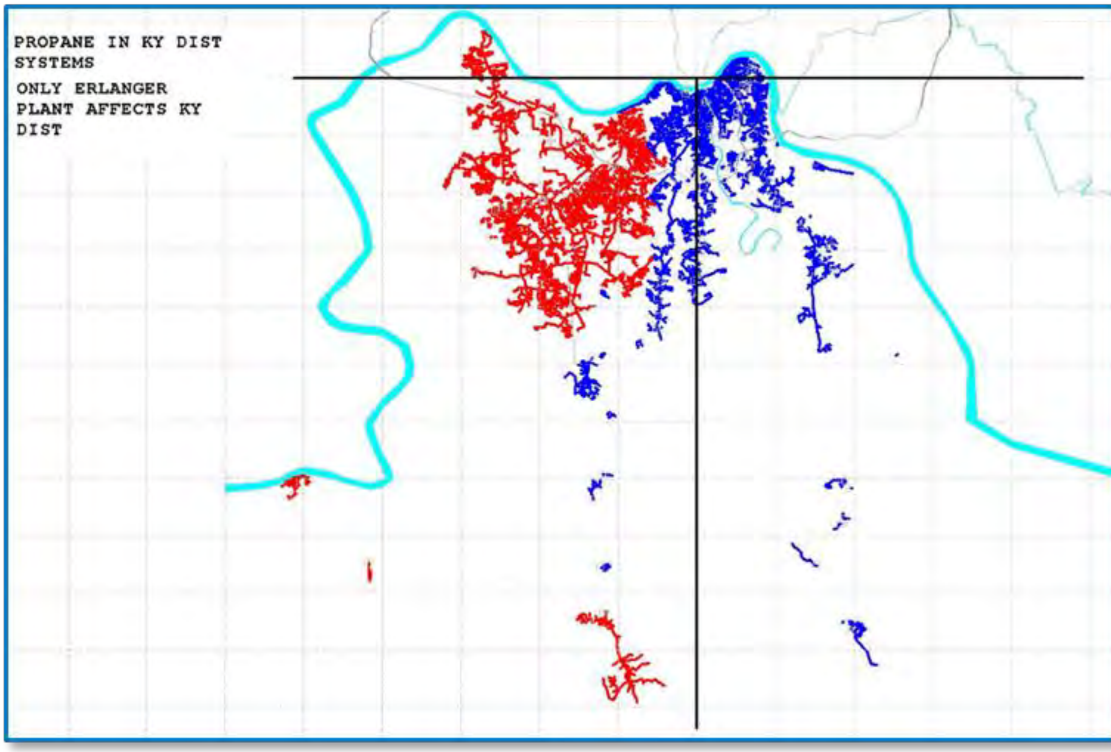


Figure 24: Propane Presence in Duke Energy Distribution System, Propane Plants Operating, Kentucky Detail

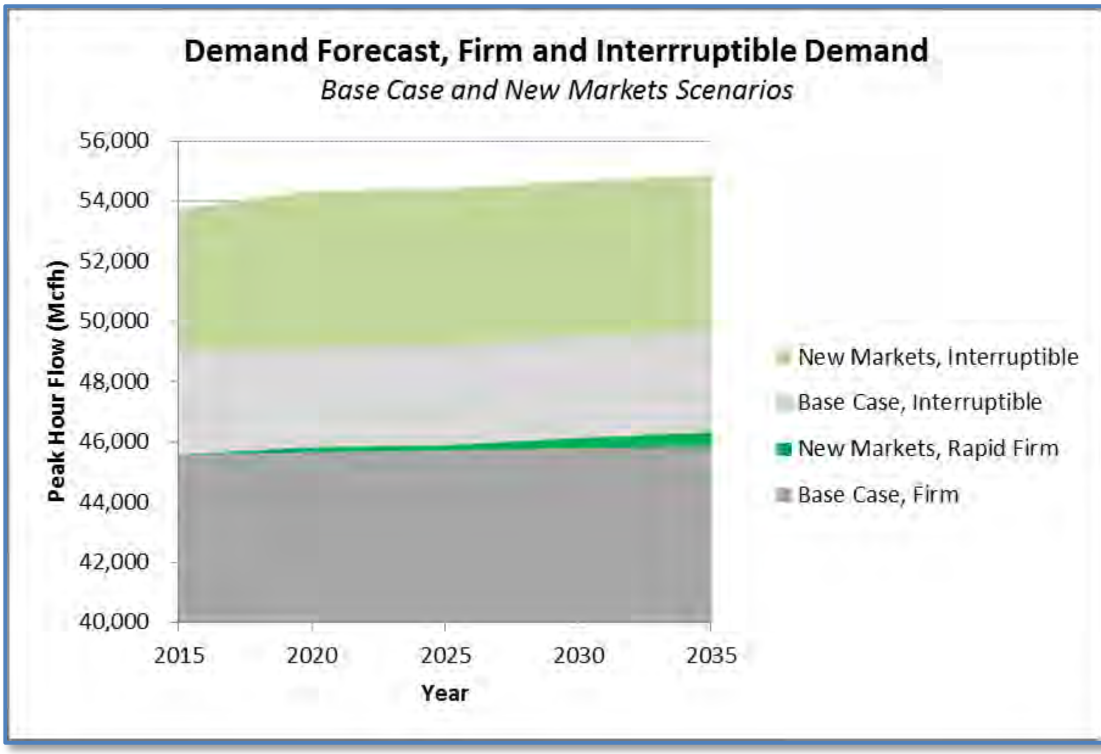


The following figures demonstrate the addition of the new markets forecast to the base case. The first chart shows firm demand only. Each new markets case includes the firm component of demand from the Zimmer facility, which is assumed to begin in 2020 after completion of system improvements, plus one of the three NGV adoption scenarios described earlier. Note that the base of the graphic does not go to zero, but rather has been increased in order to show the details of this additional demand potential.

Figure 25: Firm Demand Forecast

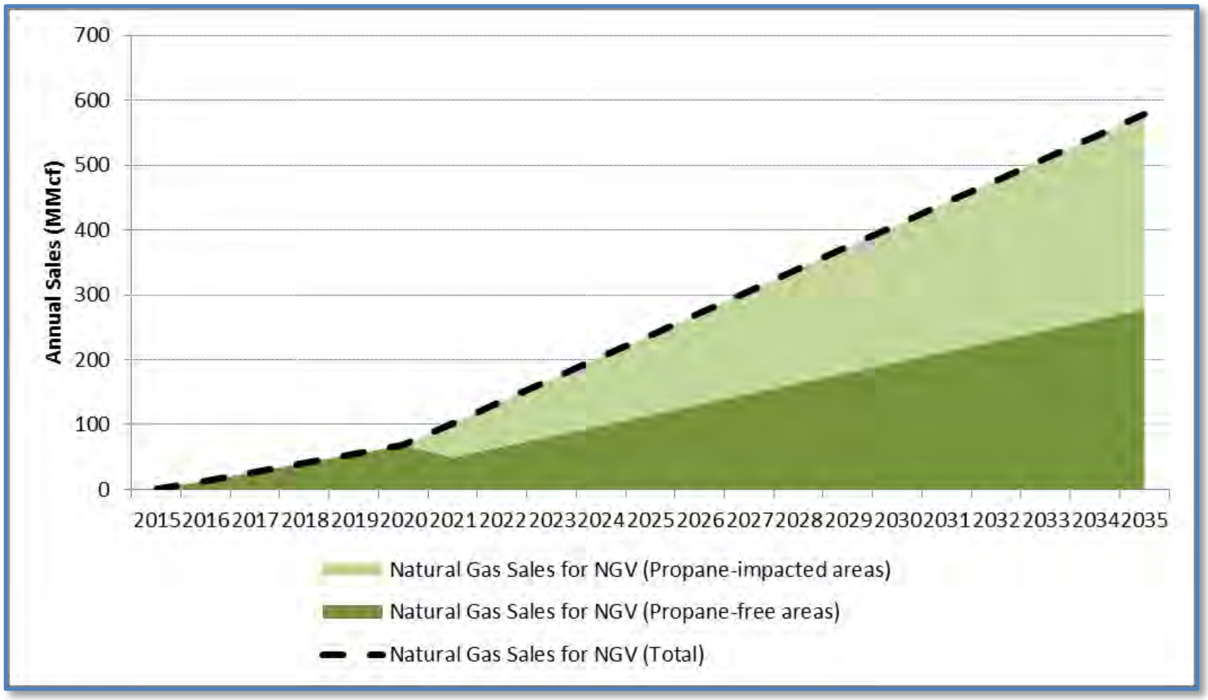
The next figure adds to this the interruptible demand with the base case interruptible demand shown in light gray and the new markets interruptible demand are shown in light green. The firm demand shown is assumed to be part of the base case (dark gray) and the "rapid" new markets case (bold green).

Figure 26: Firm and Interruptible Demand Forecast



As described in Section 3.4, New Markets, Duke Energy's ability to realize the natural gas demand growth from the NGV market scenarios is dependent upon the elimination of propane in the system, which is anticipated to be completed by 2020. Projections are based on retirement of plants by the year 2020 and elimination of propane in the system. Based on the medium adoption case, the figure below provides a graphical representation of the "at-risk" annual sales of natural gas within the NGV market if propane elimination is delayed or does not move forward. Based on an assumed rate of revenue per Mcf sales of $5.50/Mcf, this would equate to $14.6 M in "at risk" revenue in constant-year dollars over the 20-year analysis.

Figure 27: At Risk Sales if Propane is in the System



4 Planning Tools and Factors

4.1 Expansion Planning Model

For the assembly of a Gas System Master Plan, Lummus Consultants was charged with developing a list of potential capital construction projects that could be tested for their ability to improve Duke Energy's high-pressure pipeline system for the assurance of meeting customer demand over a future twenty-year period. The primary tool used to develop and analyze the capital alternatives was Duke Energy's licensed pipeline simulation model.

Duke Energy's pipeline simulation model typically serves as an operations planning tool when pipeline segments need to be taken out of service and flows have to be re-routed for continuance of uninterrupted service to Duke Energy's customers. It also serves as a broader planning tool to evaluate system enhancements/alternatives, such as pipeline pressure up-ratings, line looping, segment diameter upgrades, compression, new receipt points, pressure regulation, and other similar applications.

Duke Energy employs a commercially available, steady-state simulation model program that it customized to represent its pipeline system. The model program was originally developed by Stoner Associates, and is now marketed and maintained by another company (G.L. Noble, which is part of DNV GL, a unit of Germanischer Lloyd). It is considered to be one of the premier pipeline simulation models and is used by hundreds of gas and oil companies throughout the world. Simulation models portray the behavior of real-life systems and permit the testing of experimental changes to the system without the expense, time, or cost of actually testing a new pipe segment in the ground.

Duke Energy's simulation model has been calibrated to provide a close representation of the high-pressure pipeline grid in Duke Energy's physical system. The model is routinely checked against actual system flows to verify accurate representation. Each flow segment is represented within the model with specifications of its diameter, its maximum allowable operating pressure, its length, line connections, etc. Lummus Consultants performed all of its capital expansion scenario analyses with the assistance of Duke Energy's modeling staff, whose members ran each scenario that Lummus Consultants specified. Scenario run performance was directly observed in Duke Energy's offices and re-run under different specifications, as needed.

Gas pipeline systems flow at greatly varying throughput, subject to hourly demands that depend on the time of day and season of the year. The annual fluctuations are primarily due to weather, since many of Duke Energy's customers utilize gas for space heating. These demands are obviously greater in winter months. The time-of-day fluctuations are primarily due to work schedules, mealtime usage, and other usage habits of customers, resulting in lower demand during night-time hours and on week-ends. Typically system component expansions are needed when maximum system capacity has been attained with the throughput demanded during peak hours by firm customers. Peak demand is the observed maximum needed system throughput, and is normally used to design the size requirements of the system components. For system expansion requirements, Lummus Consultants accordingly identified design (i.e. coldest) temperature days and calculated resulting peak hourly flow rates, as discussed below, spanning the twenty-year period (2015-2035) of the Gas System Master Plan.

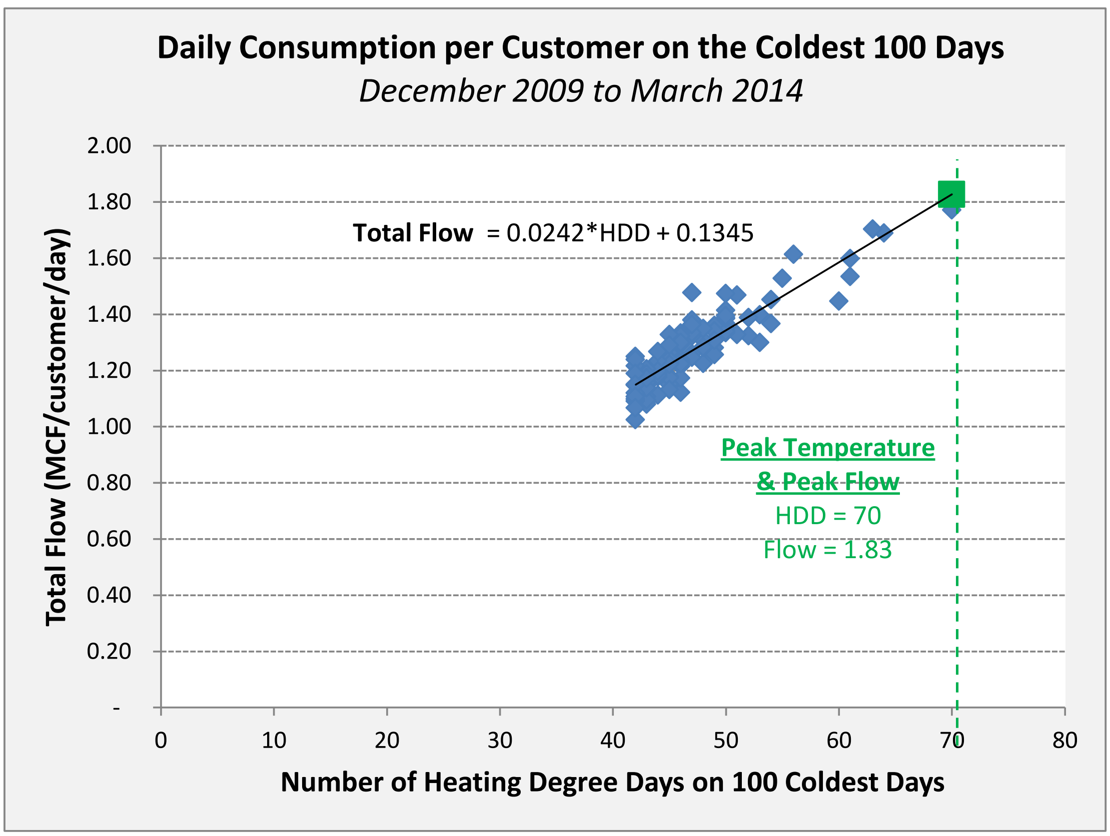
4.2 Peak Day Temperature & Peak Day Flows

For the purpose of analyzing Duke Energy's gas system for new expansions, the most significant factors in the design and planning of a gas system are the peak day temperature (i.e. heating temperature accumulations) and resulting peak day and peak hour flows. These factors are used in the simulation model to test the capacity of capital projects. For most northern gas utilities, the peak day temperature and its peak day flow typically will take place in the winter months of December, January or February.

Duke Energy utilizes supervisory control and data acquisition (SCADA) equipment to monitor the flow and pipeline pressures at gas regulator stations throughout their gas system. Duke Energy's gas control department monitors the telemetry data and records and reports the flow rates and pipeline pressures continuously at many locations throughout the pipeline system. Lummus Consultants has utilized this data to develop peak days and peak day flows for use in the simulation model.

Lummus Consultants has plotted the temperatures and flow rates experienced by Duke Energy on the coldest days in the last five winters. Fahrenheit temperatures have been converted to Heating Degree Days (HDDs) using the standard formula (HDD = 65 degrees – Temp.) in order to express results in standard gas nomenclature. Flow rates on those days include only firm demands and firm transport in both states (Ohio and Kentucky), as all interruptible demands are typically shut off, in accordance with the gas contract terms of these customers. The results are illustrated in the graph below:

Figure 28: Gas Consumption versus Temperature



As shown above, firm gas demand increases as HDDs rise (temperature falls). The coldest day experienced over the recordable period from December, 2009 through March, 2014 was on January 6, 2014, when the so-called "Polar Vortex" extended its reach into the Cincinnati area. On that day, outside temperatures averaged minus 5˚F, equivalent to an accumulation of 70 heating degree days. Observed flow on that day was 926,842 Mcf, equivalent to 1.77 Mcf/customer/day. However the best-fit line shown on the above chart indicates the demand can be expected to be even slightly higher (1.83 Mcf/customer/day) on a day averaging 70 HDDs. At the level of 1.83 Mcf/customer/day, a firm gas demand of 956,726 Mcf (1.8285*523,230) would be expected on a day averaging minus 5˚F.

Duke Energy's most recent forecast (Spring 2014) of peak-day flows is shown in the following table. Duke Energy has projected the chances of exceeding estimated peak-day deliveries at various levels of confidence, for each year through 2024.

Table 11: Duke Peak-Day Flow Projections

Year	Total Peak (Mcfd)	Firm Peaks, (Mcfd)[1]			
		50%	5%	3%	1%
2014	813,523	743,740	890,457	911,416	951,194
2015	815,148	743,911	890,661	911,626	951,413
2016	814,094	744,218	891,028	912,001	951,805
2017	814,400	744,465	891,324	912,304	952,121
2018	814,684	744,697	891,602	912,589	952,418
2019	816,347	744,950	891,904	912,898	952,741
2020	815,252	745,145	892,138	913,137	952,990
2021	815,493	745,338	892,369	913,374	953,237
2022	815,729	745,528	892,597	913,606	953,480
2023	817,284	745,710	892,814	913,829	953,713
2024	816,190	745,897	893,039	914,059	953,952
2025[2]	816,902	746,195	893,390	914,405	954,317
2030[2]	818,245	747,290	894,702	915,748	955,718
2035[2]	819,588	748,386	896,013	917,090	957,119
		Total OH and KY			

[1]Includes Firm Transmission

[2]2025, 2030, and 2035 are extrapolated

Comparing the peak-day flow (of 956,726 Mcf, smoothed) experienced on the peak day of January 6, 2014 to the 2014 data shown in the above table, indicates the 1 percent probability level of exceeding the forecast was attained on this coldest day in recent record. Lummus Consultants therefore judges use of a 1 percent probability level to be appropriate for calculating peak day flows for purposes of use in Duke Energy's simulation model. Further conversion of this flow rate to an appropriate peak-hour flow rate for use in Duke Energy's simulation model is described in the following section.

Duke Energy's records indicate that there were also similar peak demand days in January, 2005. However these are judged to be only somewhat relevant due to their age. On succeeding days starting January 19, 2005, firm demands were 938,930 Mcf; 968,271 Mcf; 978,052; and 919,369 Mcf.

4.3 Peak-Hour Factor

Peak hour flow is the highest hourly amount of firm gas demanded on the gas system infrastructure. It is usually measured in dekatherms per hour (Dth/h) or thousand cubic feet per hour (Mcfh).

A peak-hour factor is a ratio used to describe the relationship between a daily-average gas demand and a peak-hour gas demand. Peak hour gas demand typically occurs on a very cold day when only firm gas supplies are flowing. Lummus Consultants uses this factor to calculate the peak hour flow on the peak day. The peak-hour demand for each time period is used as the critical flow in the simulation model for the purpose of testing pipeline expansion alternatives.

The table below shows the ten highest daily flows reported by Duke Energy's gas control department for the past five winters. On these days only firm customers were supplied since interruptible customers had been interrupted. In a very unusual coincidence, all ten highest daily flows occurred during the same two-month period of 2014. Using these daily flows, the average hourly flow was calculated and compared to the peak hour flows for the corresponding day. On these particular ten days the peaking factor ranged from 1.10 to 1.23, with an average peaking factor of 1.15.

Table 12: Firm Gas Peaking Factors Table

Date	Total Daily Flow (Mcf)	Average Hourly Flow (Mcf)	Peak Hour Flow (Mcf)	Peaking Factor
January 6, 2014	926,842	38,618	42,358	1.10
January 28, 2014	891,192	37,133	41,860	1.13
January 23, 2014	883,834	36,826	41,647	1.13
January 7, 2014	844,089	35,170	38,611	1.10
January 27, 2014	836,541	34,856	41,463	1.19
January 21, 2014	803,008	33,459	41,161	1.23
January 22, 2014	799,367	33,307	38,026	1.14
January 24, 2014	772,791	32,200	36,045	1.12
January 29, 2014	770,971	32,124	37,871	1.18
February 11, 2014	768,311	32,013	37,628	1.18
			Minimum	**1.10**
			Maximum	**1.23**
			Average	**1.15**

This average peaking factor of 1.15 shown in the above table was used to calculate peak-hour flow forecasts for the simulation model for each future year. Results are shown in the following section.

4.4 Peak Hour Forecasts

Using the forecasted maximum daily firm gas consumption per customer from Duke Energy's ten-year forecast shown in Section 4.2 as well as the average peak-day factor of 1.15 as shown in Section 4.3, Lummus Consultants is able to calculate the appropriate peak-hour flow to be used in Duke Energy's simulation model for each forecasted year. For instance a peak-hour firm gas flow of 45,578 Mcf/hr (1.15*951,194/24) is appropriate to use in model runs covering the year 2014, as shown below at the 1 percent level.

Table 13: Peak-Hour Firm Gas Flow at 1 Percent Level

Peak Factor:	*1.15*

<--per "Peaking Factor" table, average peaking factor

Duke Energy *PEAK HOUR DELIVERIES AND PROBABILITY OF EXCEEDING (Mcf/hr)*					
Year	**Total Peak**	**Firm Peaks[1]**			
		50%	*5%*	*3%*	*1%*
2014	38,981	35,638	42,668	43,672	45,578
2015	39,059	35,646	42,678	43,682	45,589
2016	39,009	35,660	42,695	43,700	45,607
2017	39,023	35,672	42,709	43,715	45,622
2018	39,037	35,683	42,723	43,728	45,637
2019	39,117	35,696	42,737	43,743	45,652
2020	39,064	35,705	42,748	43,754	45,664
2021	39,076	35,714	42,759	43,766	45,676
2022	39,087	35,723	42,770	43,777	45,688
2023	39,162	35,732	42,781	43,788	45,699
2024	39,109	35,741	42,791	43,799	45,710
2025[2]	39,144	34,265	42,807	43,816	45,727
2030[2]	39,208	34,318	42,870	43,881	45,794
2035[2]	39,273	34,370	42,932	43,945	45,861

[1]*Includes Firm Transmission loads*
[2]2025, 2030, and 2035 are extrapolated

5 System Configuration

5.1 Current System

To serve the natural gas demands within their service territory, Duke Energy operates a system of transmission and high-pressure distribution pipelines. The system was installed in segments over the past several decades in response to the patterns of increasing demand over increasing regional expanse. Each additional pipeline segment of the system was sized according to the needs of the expansion, resulting in a mix of very different pipe diameters and pressure ratings. As it is oftentimes difficult to foresee the extent to which a regional area will grow, system expansions and extensions are generally limited by financial budgets that reflect reasonable forecasts of demand growth. When these forecasts are eventually exceeded in actual growth, the pipeline system will lack capacity and new expansions, with line replacements, pressure upgrades, line looping, compression, or other upgrades will be implemented. Such is the case in the growth of virtually every natural gas local distribution company. Oftentimes the most feasible solution to maintaining safe and reliable service is to add capacity by constructing new piping over different and circuitous routes, to avoid disrupting the encroached, densely populated areas.

At Duke Energy the piping system was built over the decades in response to changing supply, demand, technological, regulatory and political influences. Duke Energy's network of transmission and distribution lines also includes several river crossings, aged propane-air peaking facilities, a single gate station where a majority of supply is received, and pressure-limited piping infrastructure throughout many areas.

In general however, the supply of gas itself is not an issue, as the third party interstate transportation companies have the needed capacity, with some exception, and ready access to gas supplies throughout North America. The reliability and constraint issues facing the transmission system of Duke Energy relate to system configuration limitations that prevent functional and reliable balance of supply within the Duke Energy system from north-to-south and visa-versa. Adding to the balancing challenge is the situation where around 50 percent of Duke Energy's customers purchase gas supply from third parties, requiring contractual limitations on city gate locations for delivery into the system. This is part of the 'Choice Program' that is available in Ohio, but not in Kentucky. Balancing solutions could be provided within the system by either, or a combination of, new laterals, satellite LNG peaking plants, compression facilities, and the like. The implementation of a solution would necessarily consider functionality, cost, gas supply service capacity, constructability, demand growth, and bypass issues, as key determinants.

The transmission system to feed the distribution system was built from south to north, by Columbia Gulf Transmission. Today, Foster provides up to 50 to 60 percent of the system supply from Columbia Gulf Transmission (CGT) into K O Transmission Company (KOT), flowing northwards through the Kentucky portion of the LDC. The system MAOP downstream of Foster, comprised of three KOT laterals, is 650 psig. The eastern lateral crosses the Ohio River to Bethel. The central lateral goes to the Cold Spring station where the flow is regulated to meet the downstream MAOP of 392 psig, and the western lateral leads to the Alexandria regulating station, where the flow is split into two laterals and regulated to honor the downstream MAOP of about 390 psig.

There are six locations where the transmission system crosses the Ohio River into the Cincinnati LDC area. These are:

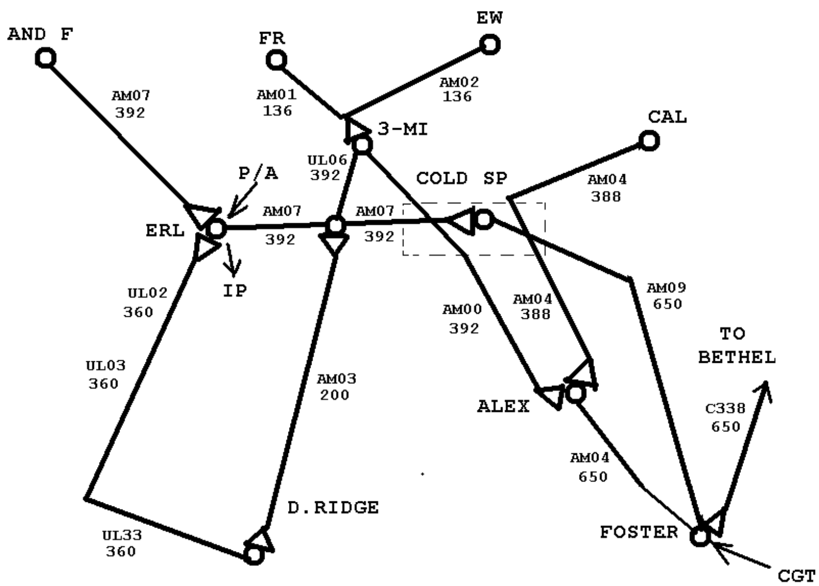
- Anderson Ferry (AND F)
- Front & Rose (FR)
- East Works (EW)

- California (CAL)
- Bracken Co
- Brown Co (BRN CO)

While south-to-north is the predominant direction of flow across the river, north-to-south flow is only possible at Anderson Ferry, East Works, and California. The California and Bracken Co. crossings are directionally drilled, while the remaining is configured with bottom-laid piping. The Front&Rose crossing will be replaced with a directionally drilled line in 2015.

A schematic of the transmission system in Kentucky is provided in Figure 29. Indicated in the figure are the line MAOPs and Ohio River crossings.

Figure 29: Duke Energy Kentucky LDC Flow Schematic

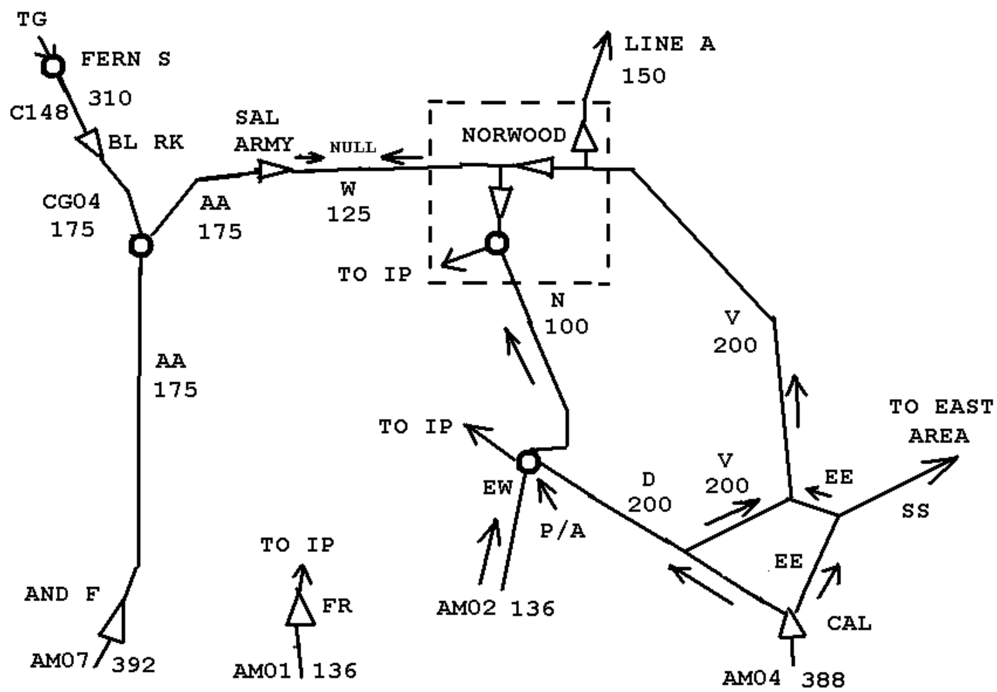


The Bracken Co river crossing serves the line to Bethel, while the Brown Co crossing (not shown) is connected directly off of CGT to the south. One of the two remaining propane-air peaking facilities is located on the Kentucky side of the river, at the Erlanger Station (ERL). This plant compresses propane air into the system at a maximum pressure of about 207 psig in the amount of up to 54,000 Mcfd natural gas equivalent.

Typically the transmission supplies from CGT in the south continue to flow north across the Ohio River into the Cincinnati distribution area.

Figure 30 shows the direction of transmission system flows for a peak day within the Cincinnati distribution area. Note that the flows cross the Ohio River, and continue to push gas supply as far north as the Norwood Station and into Line A. The MAOP limits of this area present one of the limiting factors to north-south flow.

Figure 30: Duke Energy Cincinnati Area LDC Flow Schematic

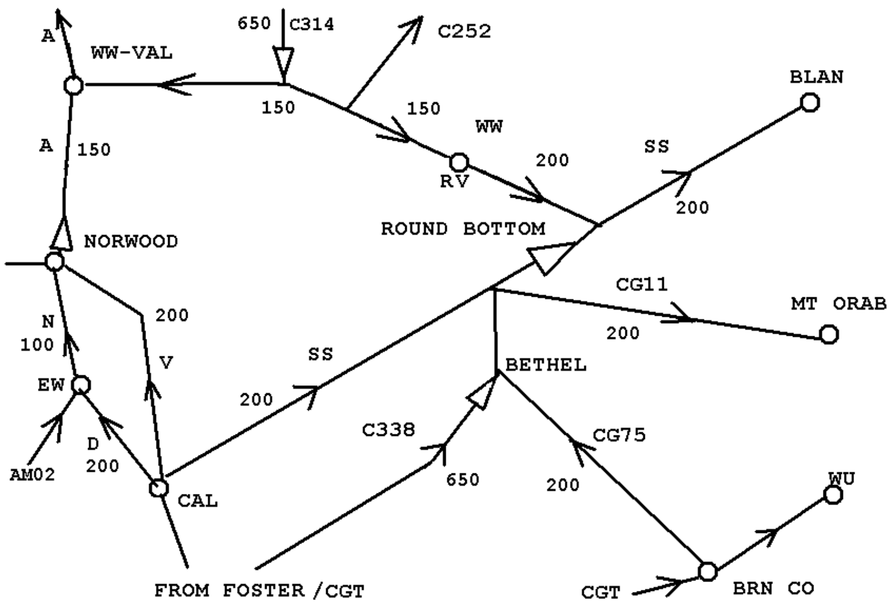


Flow from the north into the LDC in Ohio is facilitated by 21 gate stations on the interstate transmission systems of Texas Gas Transmission (TGT), Texas Eastern Transmission (TET), and ANR Pipeline Company (ANR). Gas from TGT at Fernald Station (FERN S) meets the flows from CGT to create a null point between Salvation Army and Norwood, and typically on the AA line north of Anderson Ferry.

Note that propane-air is introduced into the system at a second propane air facility, East Works, on the northern bank of the Ohio River. East Works is capable of injecting up to 1,460 Mcfhr (35 MMcfd of natural gas equivalent) into the system at up to 207 psig, similarly as the Erlanger propane air facility. Note that MAOP restrictions limit the pressure output of East Works to 100 psig.

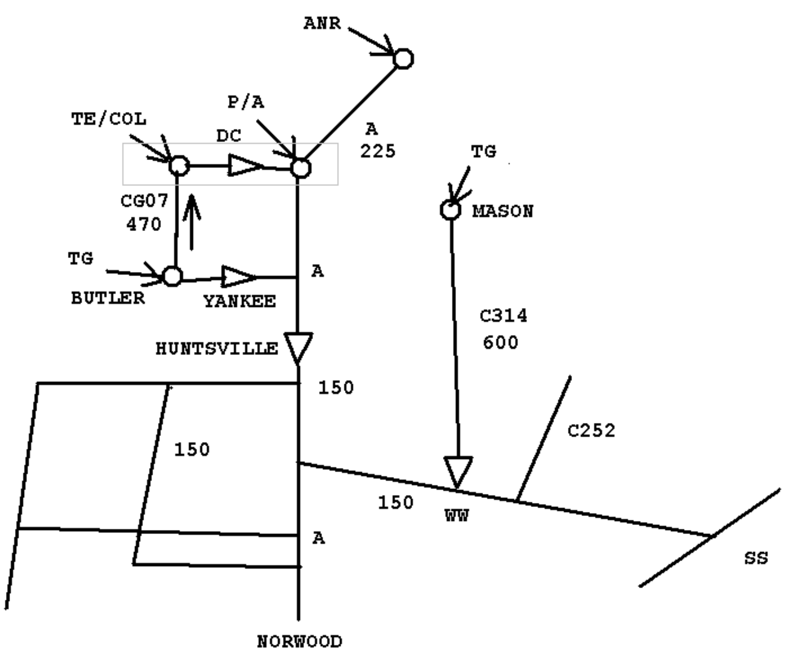
Gas flow from the south reaches the eastern areas (Blanchester, Mount Orab, and West Union) of the Duke Energy service area by way of the Ohio River crossings at California, Bracken Co, and Brown Co, into lines with 200 to 650 psig MAOP. A recently installed 10 mile, 24-inch line, with 650 psig MAOP (line C314), brings gas from the north at the TGT Mason Rd. Station to WW Station, primarily to assist with A-line deliveries. It also brings supplies to comingle with gas from the south in the SS line to Blanchester. Figure 31 illustrates these general flows to the eastern region. Note the MAOP drop from 650 psig to 150 psig where the C314 line connects with the WW Station. This MAOP reduction limits the capacity available on the C314 line to flow in greater quantities into the heart of the transmission system in a southerly direction.

Figure 31: Duke Energy Eastern Area LDC Flow Schematic



Other modeled gate stations from the north into the north distribution area are presented in Figure 32.

Figure 32: Duke Energy North Area LDC Flow Schematic



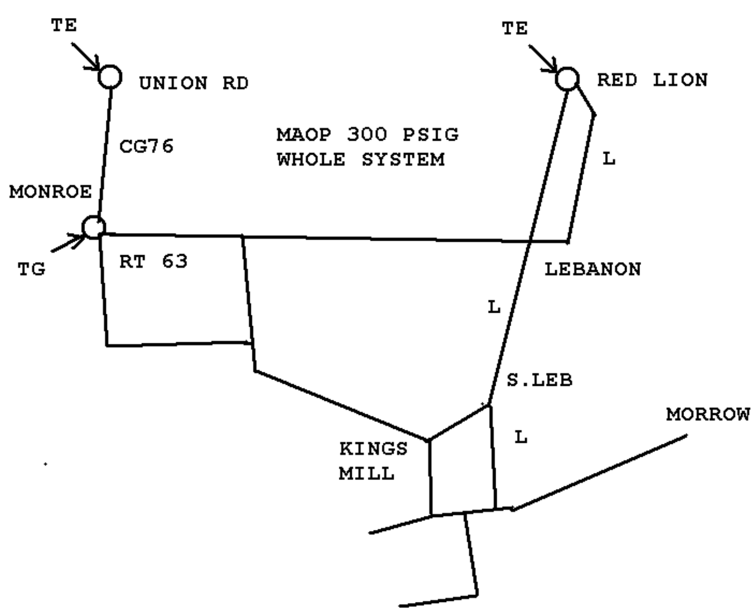
The Mason station interconnect with TGT that sends gas to WW station, as mentioned earlier, is depicted in Figure 32. Other interconnections depicted in the figure are:

- TGT at Butler station
- TET at Kennel Rd station
- TET at Dicks Creek (DC) station
- ANR at Springboro

A third propane-air plant, now inoperable, is located at DC station, also identified in Figure 32. The MAOPs of the North Area LDC appear to be 150 psig at a minimum. With the exception of gas flow northward from the Norwood station and California station, as described earlier, the remaining flows in the North Area LDC are generally in a southerly direction on peak day.

Finally, the Red Lion system, also known as the Lebanon system, or Line L system, is located at the northeastern extent of the Duke LDC. It represents about 3.5 percent of the total send-out, and is not connected to the LDC main feed/transmission system. This system is relatively expansive and does however, feed into some of the same distribution system as the other system feeds. The Red Lion system modeling schematic is presented in Figure 33. It is sourced by TET at Red Lion and Union Rd, and by TGT at Monroe/Rt 63 station. The Red Lion system is comprised of 4-inch, 6-inch and 8-inch lines having MAOPs of 300 psig.

Figure 33: Red Lion System Flow Schematic



5.1.1 Transmission Segment Diameters

A map of Duke Energy's current transmission and high-pressure distribution network is shown in Figure 34 where the diameters of the pipeline segments are identified. As indicated on the map, the broader lines correspond to greater diameters of pipe.

Figure 34: Map of Duke's Gas Network by Diameter

5.1.2 Transmission Segment Maximum Pressures

A map of Duke's current transmission and high-pressure distribution network is shown in Figure 35 where the MAOPs of each pipeline segment are identified. As indicated on the map, the broader lines correspond to greater line MAOPs.

Figure 35: Map of Duke's Gas Network by MAOP

5.1.3 Transmission Segment Flow Capacities

A map of Duke Energy's current transmission and high-pressure distribution network is shown in Figure 36 where the flow capacities of each pipeline segment are represented by color and thickness. Flow capacity mapping is a concept that depicts the thickness and color of each line segment as being proportional to the flow capacity of that segment. Flow capacity is calculated by multiplying the MAOP of each pipeline segment by the square of the diameter of that same segment. Both pressure and pipe diameter are components in calculating pipeline flow in a proportional relation.

Figure 36: Map of Duke's Gas Network by Flow Capacity

5.2 Safety, Reliability, and Flexibility

Key to the performance of a gas distribution system is the features of safety, reliability and flexibility. These features ultimately figure into the overall operational and economic functioning of the system. This Gas System Master Plan is concerned with two of the above issues: reliability and flexibility.

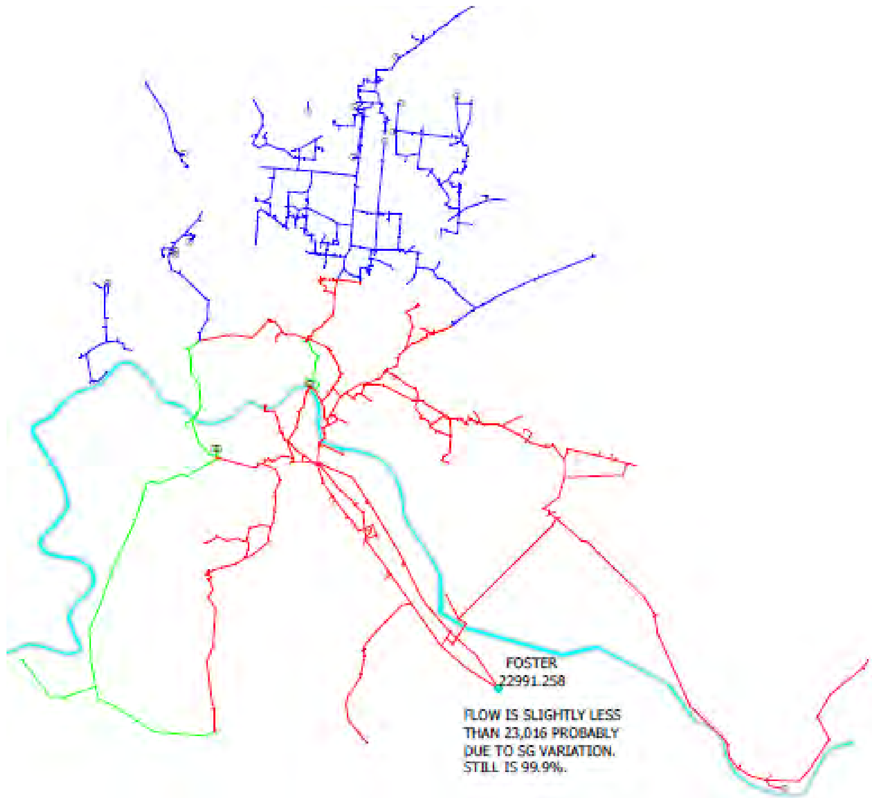
Safety is foremost the driver in ensuring a system that has the integrity to transport a combustible, high pressure gas. The piping is designed and constructed to contain the intended gas pressures, while regulating equipment are installed to assure that no segment of the system is subjected to pressures in excess of its design capacity. Further, the gas is odorized to quickly alert of any leaks. In addition to implementing methods of corrosion protection, and programs of pipe replacement, Duke Energy regularly and systematically performs inspections, testing, maintenance, and public awareness measures to assure that the system integrity is not compromised by deterioration, obsolescence, faulty equipment, or third party disruption. These matters fall under Duke Energy's integrity management program, which dictates the need for system attention to areas that indicate a threat to safety. This Gas System Master Plan is concerned only with safety issues indirectly; for instance if a transmission segment needs to undergo significant maintenance or pressure downgrading, it may help justify a new capital investment in that, or nearby segments.

A reliable system ensures gas deliveries when they are demanded. Typically reliability relates to system availability, whereas a high availability means there is minimal downtime preventing system operation. Oftentimes in systems operations, equipment redundancies are built-in to quickly switch over to, when a component needs to be taken off line for maintenance, or when a component fails. These redundancies are more common where rotating equipment is in use. Pipelines are not built with redundancy, since pipelines are generally components of high availability. The peaking plants however are built with rotating components of pumps, compressors, motors, etc., and are configured with a limited level of redundancy. Additionally, since these plants are used only during the cold weather months, there is adequate time for off-line, full service maintenance, to assure high availability when peaking service might be needed. At Duke Energy, system availability, and thus reliability, has not been an issue in past years. Records show that firm gas customers on Duke Energy's system have not incurred any major interruptions or curtailments.

While Duke Energy's system has been shown to be highly reliable in the past, the fact that over 50 percent of its gas supplies (serving about 300,000 customers) flow through a single gate station at Foster, reveals a significant exposure to reliability. Figure 37 illustrates how the system currently operates[19] with gas supply originating from the south through Foster, shown in red. The flows from the northern gate stations are shown in blue, while the two propane-air plant flows are shown in green. The extent to which the propane contribution reaches within the distribution system is shown elsewhere in this report.

[19] System sendout of 42,462 Mcfh representing record peak day, with Foster flowing at 23,000 Mcfh

Figure 37: Current System Supply Flow



Should a transportation disruption event occur at Foster, or any of the KOT/CGT lines directly connecting upstream or downstream of Foster, the consequences could be far reaching. Unfortunately, the system lacks redundancy in its ability to substitute natural gas supplies at Foster with other gate station(s). Even with such substitute station(s), the system lacks configuration flexibility in its capacity to reach the customers served by Foster. For these reasons, Lummus Consultants considered the reliability issue, as well as the following flexibility issue, foremost in the development of the Gas System Master Plan.

System flexibility is the ability of the inherent piping configuration to redirect/augment flows from other gate stations to compensate for a flow disruption. Duke Energy's system is lacking in this regard when considering a potential supply interruption at Foster. With 21 additional gate stations, it would be reasonable to assume that Duke Energy could redirect and augment its gas flow to make up for any loss at, or near Foster. The system features limiting this compensating flow redirection are several, including:

- Available contracted supply at other gate station(s) (although at times of emergency, nearby LDCs can be expected to re-direct gas to assist in maintaining adequate supply)
- Available capacity of the existing system in terms of pipe diameter and/or MAOP
- Pressure limits imposed by concurrent operation of propane air plants

Duke Energy recognizes that its system, and a large percentage of their customers, are exposed to the risk of supply interruption, should a disruptive event at only one station, Foster, occur. Duke Energy has studied various facets of its system to address this particular vulnerability, among other flexibility and reliability enhancing improvements. A study was performed in 1994 that sourced storage supply from southeast Kentucky. Additionally, one-, three-, and ten-year capital plans have been carried out, however we have been informed that these have been high level and lacked focus on key issues, such as on propane air. In another study, the Gas Research Institute was commissioned to perform an investigation on propane air. This study showed that propane air was not compatible with NGV operation. In year 2000 an external study was commissioned to review LNG peaking options. In total, these studies, we were informed, generally constitute the extent of the investigations performed. Further, these studies were of limited availability for Lummus Consultants' review. While most of these investigations focused on singular issues, subsequent Duke Energy Master Resource Plans (MRP) began looking at the various operations as one integrated system. For instance recent plans were established that included two additional phases of C314 that would extend south to California Station, however these extensions did not completely eliminate the reliability exposure. To further study this matter, Duke Energy engaged Lummus Consultants to perform a third party review to bring together all of the identified key issues under a Gas System Master Plan, that can be presented to the PUCs of Ohio and Kentucky, in support of large scale capital investment. Such an integrated resource plan is intended to consider reasonable cost solutions to their system vulnerabilities and restrictions related to:

- Relying on one source of supply to the southern area of their system, particularly on peak
- Propane air peaking facilities that are showing obsolescence, interference with flow flexibility from proposed new system extensions due to pressure limits, and interference with potential growth in the NGV sector and certain other new markets due to product incompatibilities.
- Older line performance limitations
- MAOP limitations

5.3 System Model Results for Potential New Expansions

As Lummus Consultants was charged with the development of a long-range (20-year) system expansion plan, Lummus Consultants directed its efforts at identifying the capabilities the Duke Energy's system should ultimately strive to meet. These capabilities include the ability to provide its customers substantial reliability, and to provide its transmission network sufficient flexibility to be able to recover from a wide range of potential shut-in events through redirection of flows when necessary. By defining this long-range goal, each conceived system expansion was analyzed for its ability to fulfill the goal's objectives. Included in this long-range study are configuration options for peaking facilities, which are analyzed in other sections of this report.

5.3.1 Long-Range Capabilities

The emphasis placed on defining scenarios to run on the Stoner pipeline simulation model was toward reliability and flexibility. Reliability was considered a top criterion due to the current dependence on a single gate station to serve over half of the system's firm customers and the overwhelmingly obvious consequence posed by a possible shut-in event at or near this station. A system of greater flexibility, in particular a system capable of reliably serving the southern segments from northern gate stations, would not only insulate against the specter of loss of gas supply to a majority of customers, but would likely also result in lower cost in terms of asset management including those participating in the customer Choice program. Other features reflected in modeling selection considered regions of concentrated demand growth, population class category, and imminent transmission pipeline replacement or pressure downgrades. These features were considered as refinements to the primary objective of enhancing the system for reliability and flexibility.

5.3.2 Capacity of Current System Configuration

Figure 38 represents Duke Energy's transmission lines overlaying the Ohio River (shown in light blue color). Serving the system-wide peak demand of 42,462 Mcfh, the figure reveals the extent of flow originating through Foster, assuming the two propane air peaking plants, Erlanger and East Works, are not in operation. The volume contribution from Foster in this scenario amounts to 25,511 Mcfh, extending into the system, as illustrated in red in the figure below. The lines of dark blue represent the remaining volumes as served by the northern gate stations. This graphic essentially represents the hydraulic capability of the system to serve demand from the south through Foster without propane air augmentation. While this exercise shows that the system in its current physical configuration is capable of eliminating the need for propane air plants, the required increased flows through Foster are not likely deliverable by CGT. Alternatively, increasing flow from the northern gate stations is not possible, as model runs have shown that the aggregate system capability will handle only 16,951 Mcfh from the north, likewise assuming no propane contribution from the two plants. The flow pattern for this latter scenario is closely represented in Figure 38. More on options to eliminate the need for the propane air facilities are discussed elsewhere in this report.

Figure 38: System Capacity as Served from the North and South

In order to analyze a wide range of potential expansions that could reduce or eliminate the reliability exposure presented by the reliance on flow through Foster Station, Lummus Consultants supervised the following nine Stoner simulation runs. They analyze the specific capabilities of potential expansions in the Center, Western, and eastern portions of Duke Energy's service territory. Each scenario assumes a system peak sendout of 42, 462 Mcfh, available Foster pressure of 400 psig, and no contribution from the propane air plants.

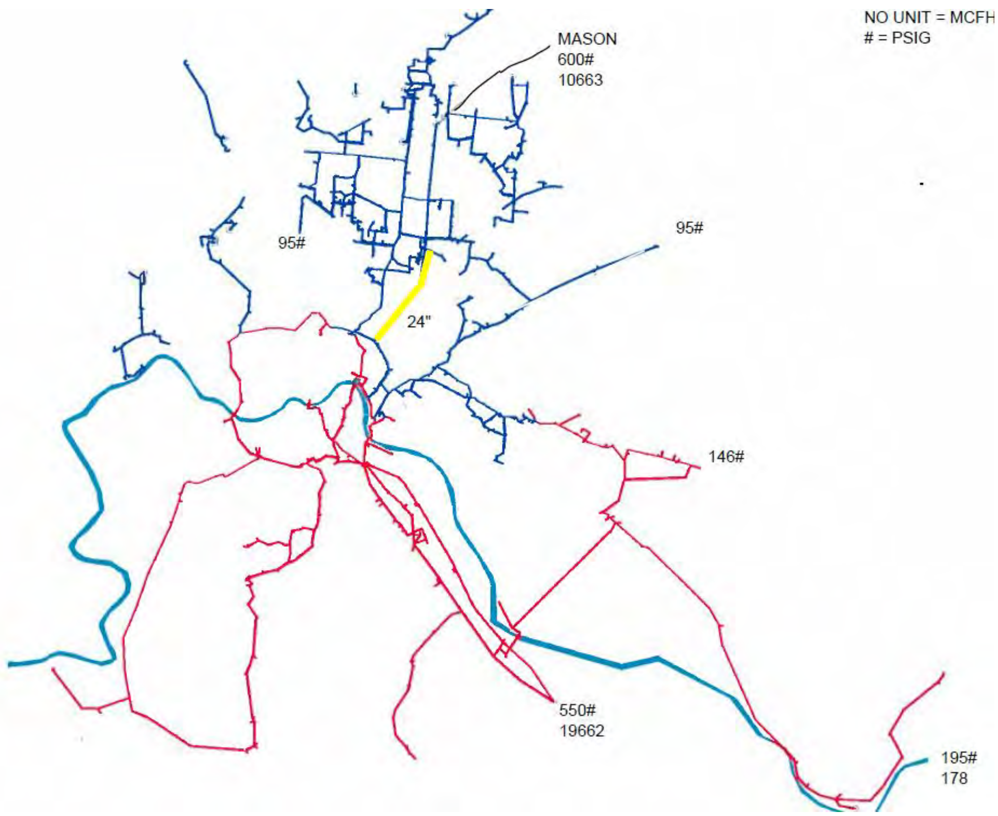
5.3.3 Description & Analysis of Potential New Expansions

5.3.3.1 System Center Expansions

The following describes the C-1, C-2 and C-3 expansions.

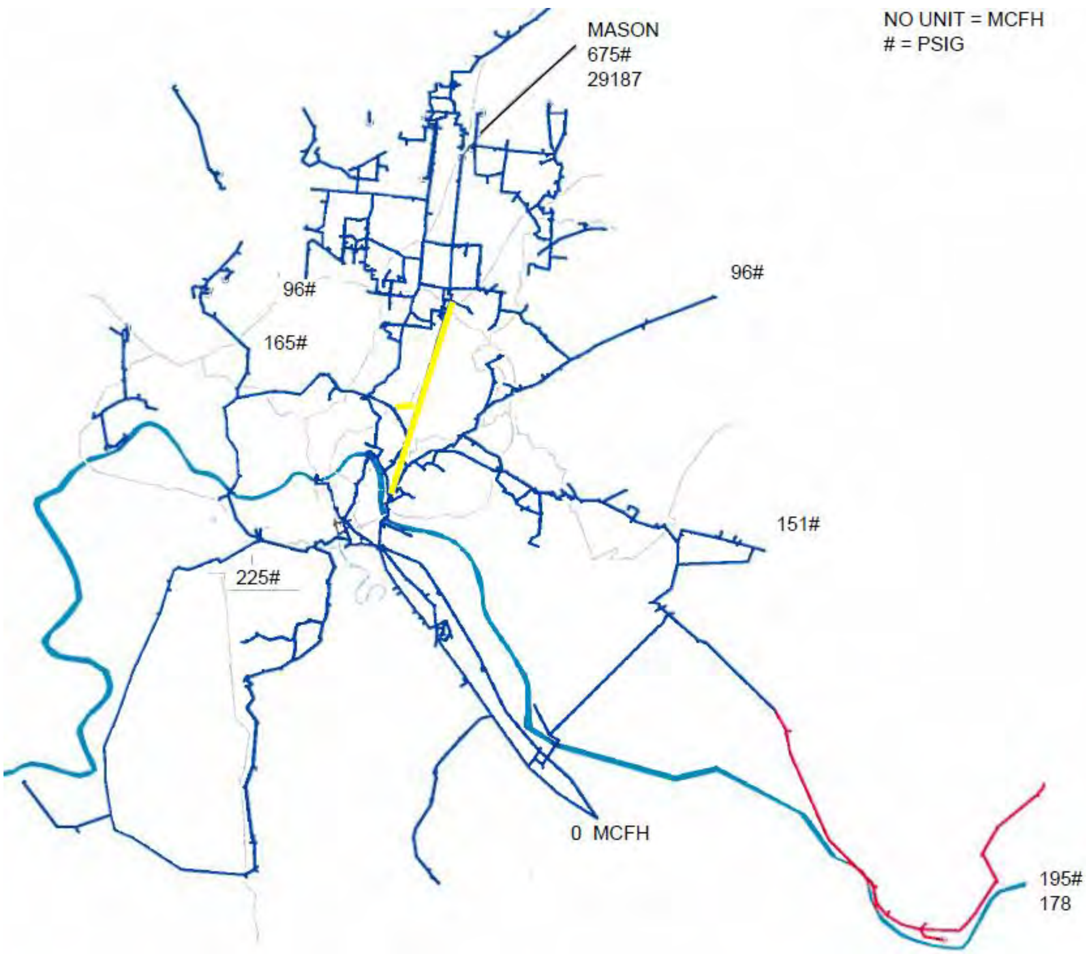
C-1 Expansion – Much consideration has been given to the proposal of extending the high capacity C314 line an additional 9.8 miles with 24-inch pipe to connect to the V-line east of the Norwood Station. This scenario was modeled and is represented in Figure 39. With Foster flow indicated in red, the figure shows how this C314 extension backs-off Foster gas north and east of Norwood. It is seen that northern gas reaches through nearly all of the 20-inch V-line, into the EE-line near California Station, and eastward to around Batavia where it meets flow from the south to create a null-flow point. Increased flow in this case is predominantly limited by the capacity of the V-line. This scenario reduces Foster reliability to 19,662 Mcfh, the difference at Foster being accommodated by flow through the Mason station.

Figure 39: C-1 Expansion C314 Line Extension to V-Line



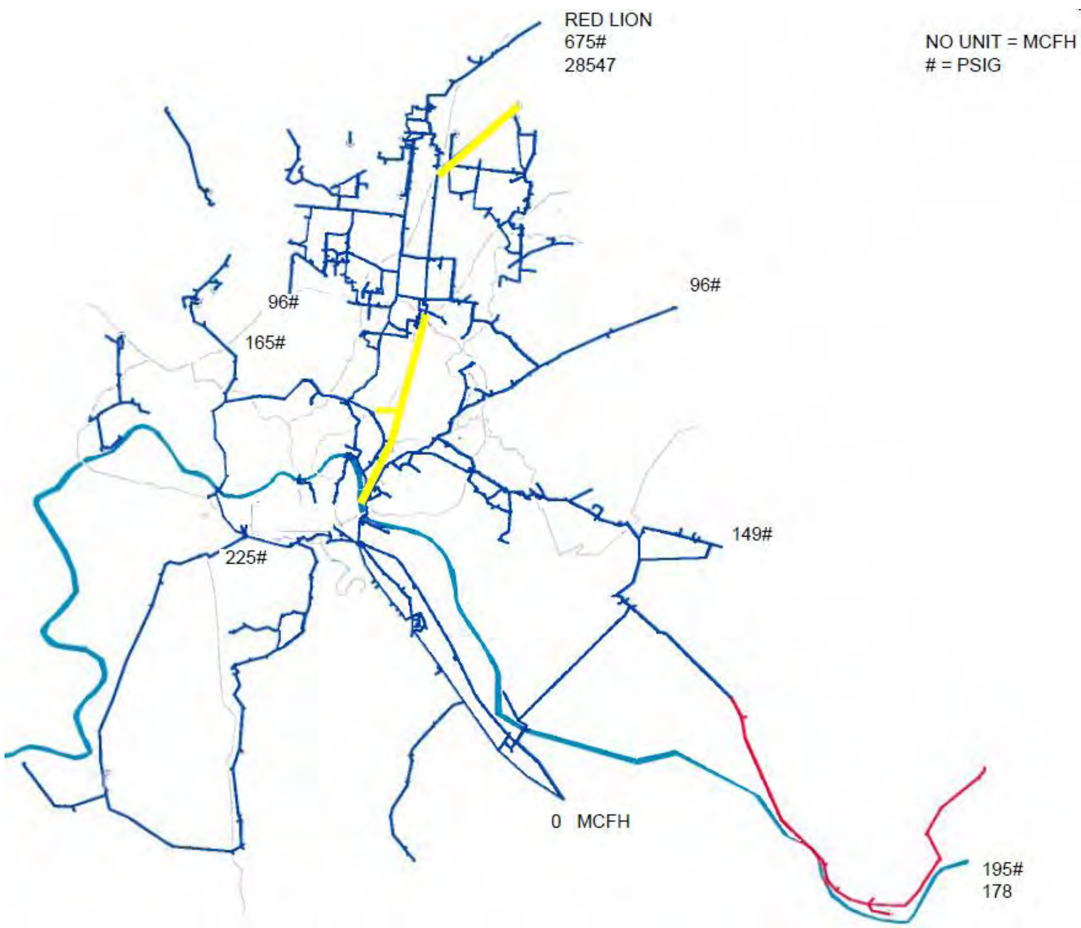
C-2 Expansion – Through multiple runs with the pipeline simulation model, it has been determined, that to reduce the Foster flows entirely and thereby eliminate the reliance on this gate station, a new feed lateral would need to be installed to the California station. Such a line would not rely on the limited V-line capacity, and meet the minimum required pressures around the California station to flow in both directions eastward and westward. This C-2 Expansion scenario assumes the C314 line is extended to California station with 18.7 miles of 36-inch pipe, plus about 1.6 miles of 16-inch pipe to maintain a connection with the V-line. The model was forced to back-off the Foster flows as much as possible. In this case Foster flow was reduced entirely, requiring about 29,187 Mcfh from the Mason station. The limiting feature in this case is the C314 line, which creates significant pressure loss, requiring the relatively larger size 36-inch line to California. Note that the system serving Georgetown to West Union is accessed through the CGT connection over Brown Co station. Figure 40 shows how the flow from the north completely serves the Duke Energy system, with exception to the above mentioned Brown station receipts.

Figure 40: C-2 Expansion WW to California Station



C-3 Expansion – The flexibility to connect the C-2 Expansion with a greater number of interstate pipelines is enhanced by building a lateral from Mason to Red Lion. This is represented in the C-3 Expansion. It requires 9.9 miles of 36-inch pipe connecting Mason to Red Lion (Lebanon Hub), in addition to the pipe configuration required in the C-2 Expansion. In this scenario Red Lion provides approximately 28,547 Mcfh to the system sendout. Figure 41 illustrates this flow scenario, indicating a required pressure at Red Lion (Lebanon Hub) of 675 psig, and essentially the same system flow patterns as the C-2 Expansion.

Figure 41: C-3 Expansion Red Lion to Mason as Extension of C-2 Expansion

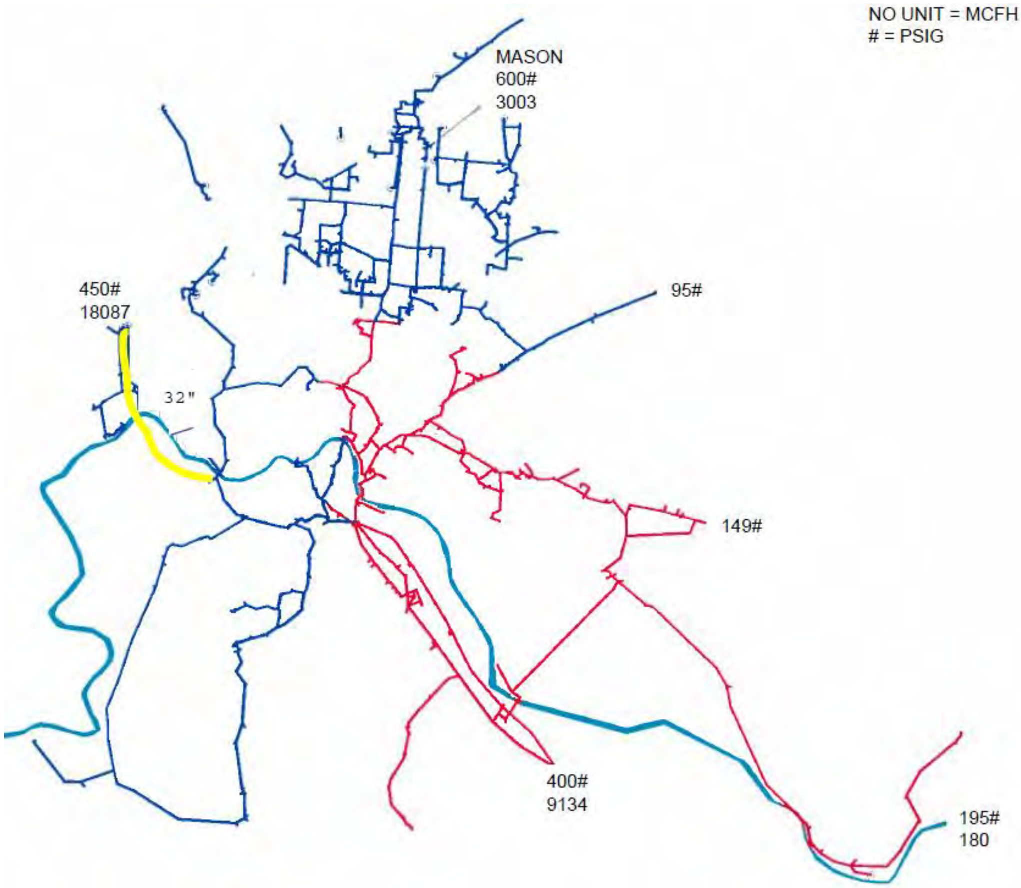


5.3.3.2 System West Expansions

The following describes the W-1, W-2 and W-3 expansions.

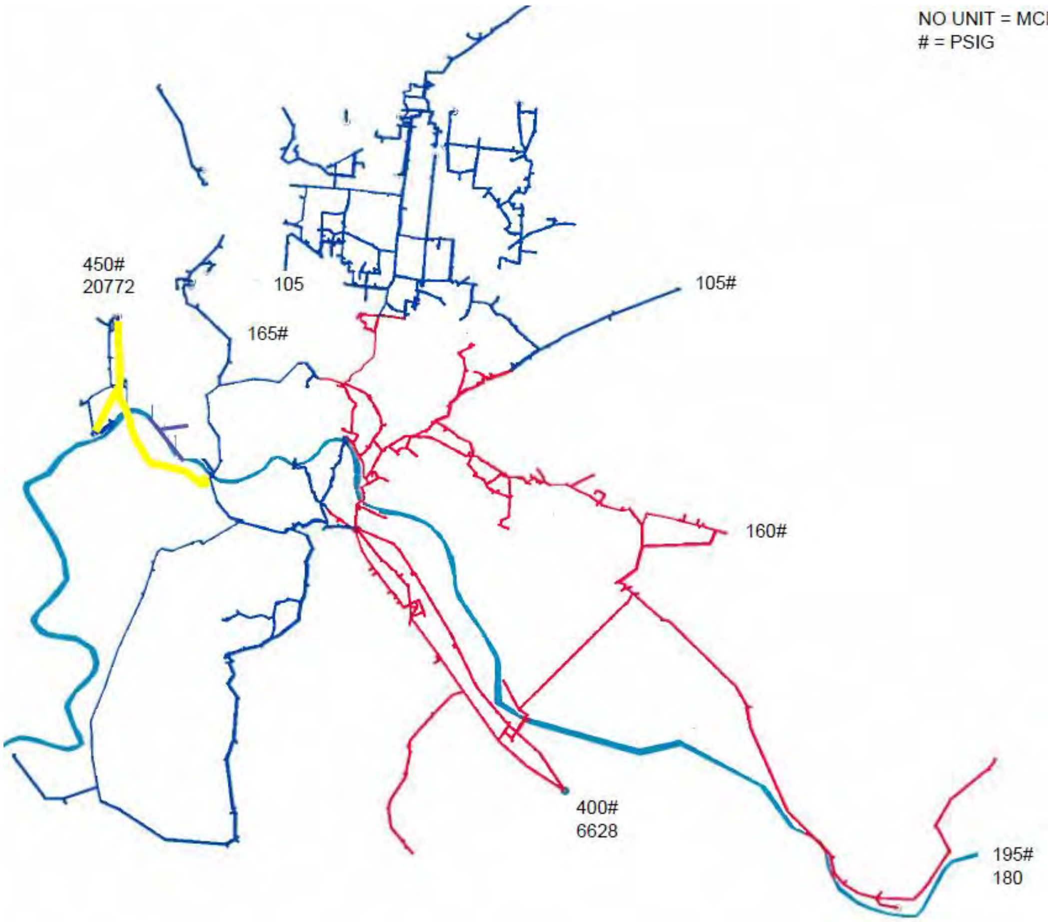
W-1 Expansion – An alternative option to bring gas from the north is represented in Figure 42 where, instead of the C314 extension, a new 32-inch lateral of 18.1 miles was sized to bring gas from TGT at Harrison Station, southward across the Ohio River, to connect with the AM07-line on the Kentucky side of Anderson Ferry. Here the gas enters the AM07-line to flow southward and across Anderson Ferry northward on the AA-line. With both of the propane air facilities shut-in, the required flow from Foster is reduced to only 9,134 Mcfh, displayed graphically in red in Figure 42. As seen in the figure, Foster gas still reaches well north of the Norwood Station by way of California to East Works, but is backed-off at Cold Springs by gas from TGT gas originating at Harrison. The limiting factor for increasing volume in this scenario is the flow capacity of the new lateral given the pressure at Anderson Ferry.

Figure 42: W-1 Expansion Harrison to Anderson Ferry



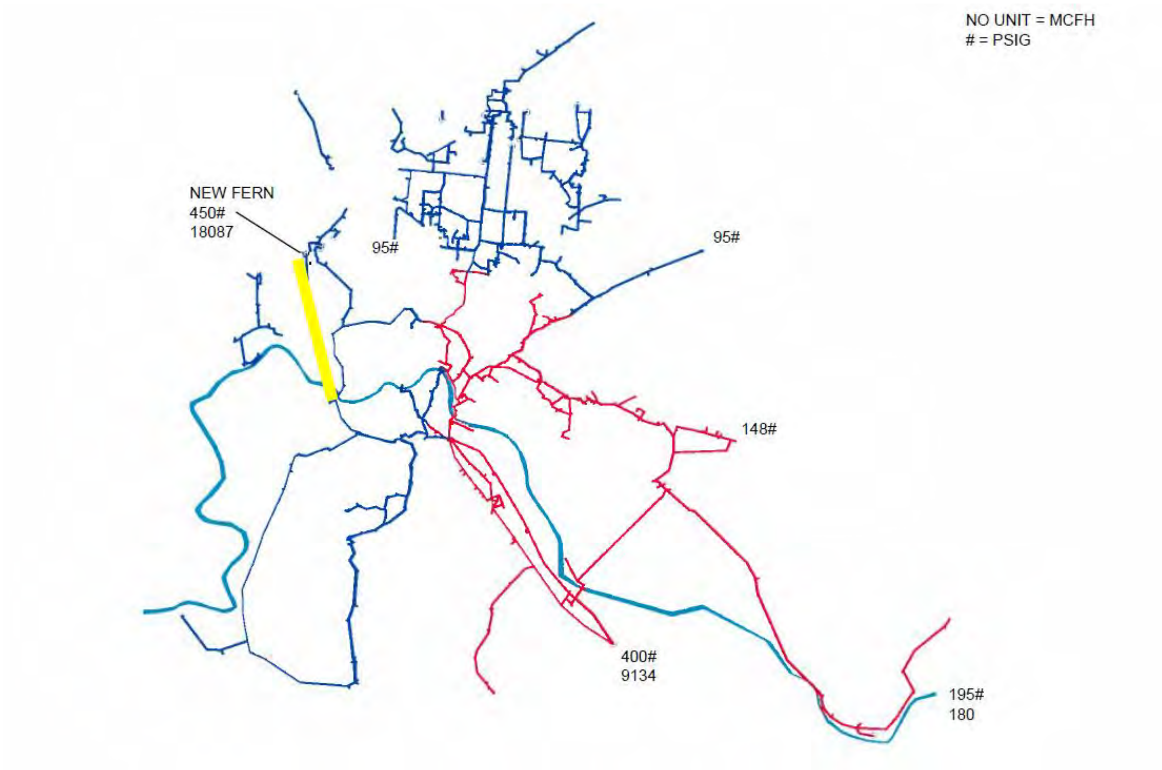
W-2 Expansion – A variation of the Harrison to Anderson Ferry expansion may consider serving the Miami Fort power plant. To meet the flow requirements, the revised lateral would need to be constructed with a 36-inch line over the first 7.6 miles, and 32-inch line over the remaining 10.5 miles. A connecting 16-inch lateral of 3 miles is sized to bring the gas from the W-2 Expansion to the Miami plant. The use of the 36-inch segment on peak would allow greater flow under the same pressure limits at Anderson Ferry. In this case Foster flow is further reduced to 6,628 Mcfh and Harrison receipts are increased from 18,087 Mcfh in case W-1 to 20,772 Mcfh in case W-2. Figure 43 identifies some of the key pressure and flow points on the system for the W-2 expansion.

Figure 43: W-2 Expansion Harrison to Anderson Ferry with Upsized Lateral



W-3 Expansion – Modeling runs have shown that the same results of W-1 Expansion can be achieved with a similar 32-inch lateral to Anderson Ferry, originating at the TGT Fernald Station, stretching over 21.6 miles. This alternative, while approximately the same distance from Harrison, may have right of way (ROW) acquisition and construction advantages. Serving the Miami Fort power plant is not a considered feature of this expansion, due to the increased length of required piping lateral to the plant. Figure 44 illustrates the flow patterns and identifies some of the key pressure and flow points on the system for the W-3 Expansion. Note the similar system data points as for the W-1 Expansion.

Figure 44: W-3 Expansion Fernald to Anderson Ferry

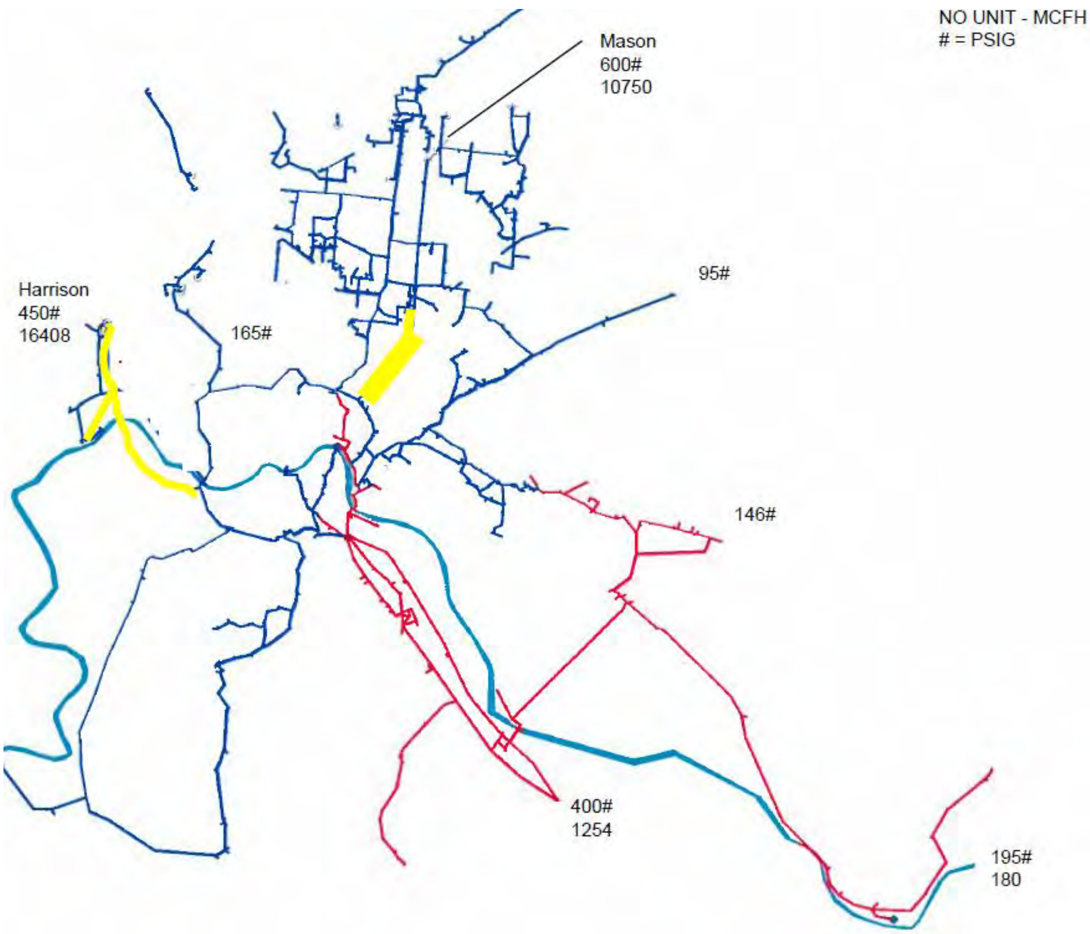


5.3.3.3 Combined System Center and West Expansion

The following describes the combined C-1/W-1 and C-2/W-2 expansions.

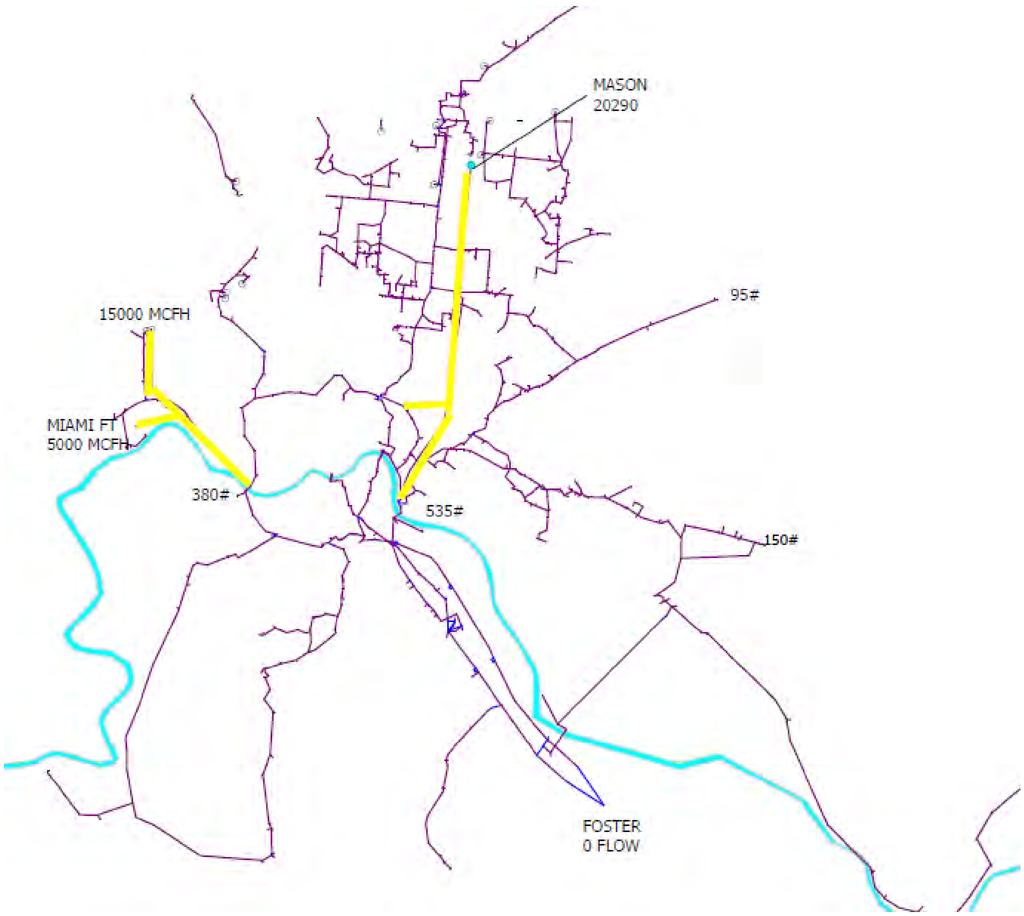
C-1/W-1 Expansion – By combining the foregoing C-1 and W-1 expansions, it can be shown that the flow through Foster is significantly reduced to 1,254 Mcfh. Figure 45 illustrates the reduced flow from Foster reaching Norwood from Cold Springs, through California and East Works. Additionally, as expected, the eastern system to Mt Orab is still served by Foster over Bracken Station. The restriction to even greater volume of flow is related to the individual expansion restrictions, as identified above. The combination of the two system enhancements is a considerable improvement in the reliability to serve the southern part of the LDC, although the additional volumes are sourced from only one interstate pipeline, TGT. In that sense the system flexibility is only modestly improved.

Figure 45: Combined C-1 and W-1 Expansions



C-2/W-2 Expansion – By combining the foregoing C-2 and W-2 expansions, it can be shown that the flow through Foster is likewise reduced to zero, attributable to the C-2 individual expansion. Further, by including the W-2 expansion, a high demand customer, Miami Fort power plant, may be served on the west side of the system. Figure 46 illustrates the eliminated flow from Foster being replaced by flows from Mason and Harrison. The combination of the two system enhancements, while eliminating the requirements through Foster, reduces the required flow through Mason from 29,187 Mcfh to 20,290 Mcfh (for the C-2 option alone), and reduces the required flow through Harrison from 20,772 Mcfh to 15,000 Mcfh (for the W-2 option alone). The additional volumes from the northern gate stations required to reduce the Foster requirements are however, sourced from only one interstate pipeline, TGT. In that sense the system flexibility is only modestly improved.

Figure 46: Combined C-2 and W-2 Expansions

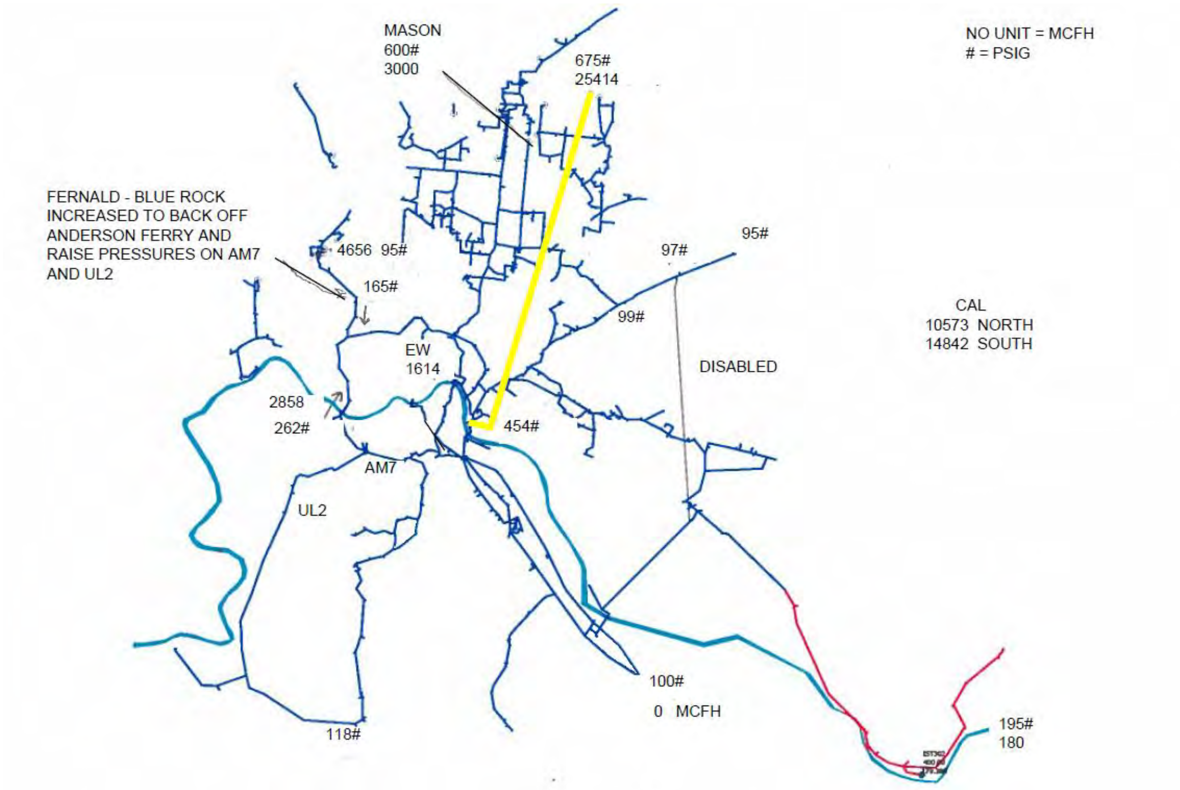


5.3.3.4 System East Expansion

The following describes the E-1 expansion.

E-1 Expansion – Owing to the proximity of the Lebanon hub (i.e. Red Lion Station) within the Duke Energy service area, and the possibility to connect to multiple interstate pipelines, as was done in the C-3 Expansion, it is recognized that receiving significant gas supply at Red Lion (Lebanon Hub) offers the utmost in system supply flexibility. Integrating this flexibility into the system to promote maximized reliability for a system east expansion, requires a connecting line reaching from Red Lion to the California Station. The model results show that a nominal 30-inch diameter pipeline of 44 miles, receiving gas from Red Lion and delivering at/into the California Station, will eliminate the need for gas receipts through Foster. This is shown in Figure 47 where the system flow, indicated in blue, originates from northern gate stations, reducing Foster volumes to zero. The routing of this new line may take advantage of considerable existing ROW, as available.

Figure 47: E-1 Expansion Red Lion to California



5.3.4 Summary of Flows, Costs & Foster Reliability of Potential New Expansions

Table 14 summarizes the above described expansion scenarios with resultant flow reductions at Foster and required new gate station volumes. Note the footnotes describing specific features.

Table 14: Summary Expansion Results at 42,462 Mcfh System Sendout and no Propane-Air Contribution

Run	Description	New Gate Location	New Gate Volume(1)	Foster Flow Requirement(2)
Fmax	Foster Flow Maximized	N/A	N/A	25,512 Mcfh
Nmax	Northern Flow Maximized	N/A	N/A	25,511 Mcfh
C-1	24" WW to V-Line	Mason	10,663 Mcfh	19,662 Mcfh
C-2	36" WW to California	Mason	29,187 Mcfh	0 Mcfh
C-3	C-2 Run plus 36" Red Lion to Mason	Red Lion	28,547 Mcfh	0 Mcfh
W-1	32" Harrison to Anderson Ferry	Harrison	18,087 Mcfh	9,134 Mcfh
W-2	36"/32" Harrison to Anderson Ferry serving Miami Ft at 5,000 Mcfh(3)	Harrison	20,772 Mcfh	6,628 Mcfh
W-3	32" Fernald to Anderson Ferry	Fernald	18,087 Mcfh	9,134 Mcfh
C-1/W-1	Combined C-1 & W-1 Runs (4)	Mason and Harrison	Mason 10,750 Mcfh Harrison 16,408 Mcfh	1,254 Mcfh
C-2/W-2	Combined C-2 & W-2 Runs	Mason and Harrison	Mason 20,290 Mcfh Harrison 15,000 Mcfh	0 Mcfh
E-1	30" Red Lion to California	Red Lion	25,414 Mcfh	0 Mcfh

(1) New Gate Station Volumes include current station throughput
(2) Volume to meet total system demand of 42,462 Mcfhr with no Propane-air augmentation
(3) Miami Ft volume of 5,000 Mcfh assumed start up only
(4) California flow is 1,140 Mcfh if pressure is lowered to 400 psig

Legend:
Fmax reflects the forced maximum flow from Foster as limited by system capacity
Nmax reflects the forced maximum flow from northern gate stations as limited by system capacity
C-expansions are generally along the center of the system
W-expansions are generally on the West of the system
E-expansions are generally on the East of the system

Table 15 Summarizes the Expansion metrics with estimated construction cost ranges. Also, an estimate of the cost benefit for added system supply flexibility is indicated. This cost benefit is estimated from savings anticipated through simplified supply asset management services and Choice Program flexibility enhancement.

Table 15. Expansion Scenarios Metrics

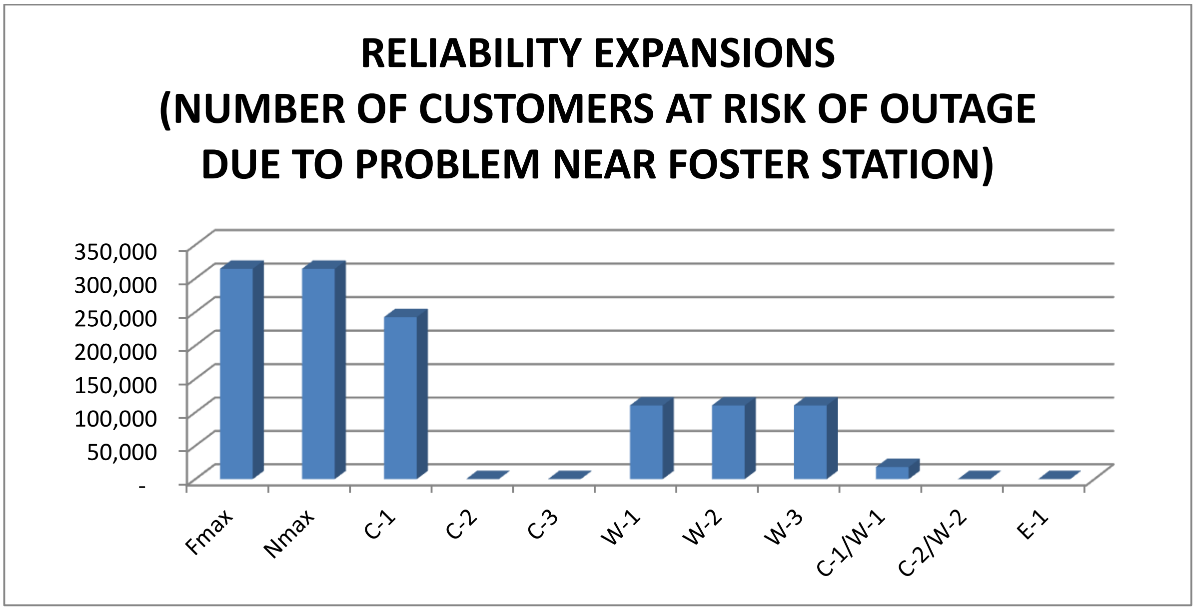
Run	Description	Dimensions: Est Length, mile	Dimensions: Nom Dia, inch	Estimated Cost (6): Low, $1000	Estimated Cost (6): High, $1000	Flexibility Cost Benefit(1), $1000
Fmax	Foster Flow Maximized	N/A	N/A	Existing System		-
Nmax	Northern Flow Maximized	N/A	N/A	Existing System		-
C-1	24" WW to V-Line	9.8	24	52,181	111,817	20
C-2	36" WW to California	18.7	36			
	16" to V-line	1.6	16			
	totals	20.3		106,078	227,311	340
C-3	C-2 (see above)	20.3	various			
	36" Red Lion to Mason	9.9	36			
	totals	30.2		149,163	319,636	340
W-1	32" Harrison to Anderson Ferry (2)	18.1	32	74,278	159,168	200
W-2	36" Harrison to Miami Ft take-off	7.6	36			
	32" Miami Ft take-off to And. Ferry	10.5	32			
	16" Miami Ft take-off to Miami Ft (3)	3	16			
	totals	21.1		81,349	174,320	200
W-3	32" Fernald to Anderson Ferry	21.6	32	136,438	292,366	200
C-1/W-1	Combined C-1 & W-1 Runs (4)			126,459	270,985	311
C-2/W-2	Combined C-2 & W-2 Runs			187,427	401,631	340
E-1	30" Red Lion to California (5)	43.4	30	128,629	275,633	340

(1) Est by Jeff Kern and does not include transportation customer benefit, which could double given estimate
(2) Requires 500 psig at Harrison; 36-inch line is required for 450 psig at Harrison
(3) Assumes 450 psig at Harrison; serves Miami Ft at 5,000 Mcfh
(4) Harrison requires only 390 psig
(5) Assumes 675 psig at Red Lion
(6) Based on Lummus Consultants Class 5 cost estimate, with Duke refinements resulting in -30/+50% estimate incl. 1.5% inflation over 5 years

The expansion scenarios identify the volume reductions potentially realized on CGT through Foster. The benefit of these volume reductions places fewer customers at risk should a Foster-related event occur. The estimated number of customers remaining at risk under each of the expansion scenarios, assuming a full shut-down of Foster, is presented in Figure 48. The number of customers is estimated in direct relationship with the remaining required flow through Foster to serve the system for each expansion scenario.

It is important to note, that while the customers served through Foster station are represented in Figure 48, the customers receiving gas from CGT over Brown Co station, on the system serving Georgetown to West Union, are not represented in the figure. Should an event on CGT impact the Brown Co station receipts, then it is expected that roughly 1,800 customers would be affected, regardless of the expansion option chosen from this study. To safeguard the Brown Co station customers against an event on CGT, would require additional lateral expansions/upgrades to adequately receive gas from one of the northern gate stations. The option to reduce the risk to these customers has not been studied in this assignment.

Figure 48. System Reliability Improvement at Foster Under Expansion Scenarios – Customers Remaining at Risk



6 U.S. Peak Supply Facilities

This chapter provides the reader with information on the types of peaking facilities in general use in the United States. Storage facilities are typically constructed above-ground in steel containers protected from spillage by means of dikes. In contrast, Duke Energy's usage of underground mined caverns for propane storage is virtually unique in the industry.

6.1 Propane-Air Plants

6.1.1 Purpose of Propane-Air Facilities

Most gas companies in the U.S. have two broad categories of gas supply: 1) base supplies generally purchased from nearby Interstate pipelines through long-term supply contracts, and 2) peaking supplies that often exist within the service area of the gas company and are operated by the company. Base supplies cover seasonal and year-round demand requirements of the company's customers, whereas peaking supplies fulfill the most temperature-driven requirements of their customers; primarily winter-time space-heating needs. The balance between the size of the two types of supplies is determined by costing the volumes of winter supplies required: in the past it has generally, but not always, proven to be most economical for a gas company to purchase base supplies for the vast majority of its annual customer demand and only utilize peaking supplies for a few weeks per year.

The predominant types of peaking facilities used by gas companies in the U.S. are LNG and propane air. Many gas companies have both types of peaking facilities, using LNG for more extended periods (several weeks per year) and propane-air facilities for shorter, higher-demand periods (several days per year). The days that these facilities operate are generally not continuous; for example one or two days one week and one or two days some time later, depending on weather severity.

6.1.2 Components of Propane-Air Facilites

Propane is a heavier hydrocarbon than methane, which is the primary component of natural gas. As such it has a higher heating value per cubic foot than methane and cannot be used directly in natural gas. Propane must first be cut back with air in order to lower its heating value to approximately that of natural gas. Propane is stored at propane-air peaking facilities, mixed with air, compressed, and then blended with natural gas in fixed proportions.

6.1.3 Number of U.S. Propane-Air Facilities

There are a number of propane-air facilities within the U.S. as shown in the following table, which lists the number of existing facilities in each state:

Table 16: Propane-Air Plants in the United States

State	Number of Facilities
Alabama	1
Connecticut	4
Illinois	3
Indiana	2
Iowa	2
Kentucky	1
Maryland	3
Massachusetts	9

State	Number of Facilities
Minnesota	4
Missouri	1
Nebraska	1
New Hampshire	1
New Jersey	4
New York	2
North Dakota	1
Ohio	3
Pennsylvania	4
Rhode Island	1
South Carolina	2
Virginia	7
Total	**56**

Source: "Preliminary Assessment of a Propane-Air Backup System for the Anchorage, Alaska, Area," Argonne National Laboratory, ANL/DIS-12-5, February, 2012.

In the above table three propane air facilities are listed for Ohio and one for Kentucky.

6.1.4 Compatibility/Incompatibility of Propane-Air Supplies

By blending propane with air and with natural gas in specific proportions, compatibility is achieved for burning characteristics such as flame height and flame color in customer appliances. This propane/air mixture is directly compatible with natural gas and can therefore be used by any natural gas fired equipment, such as burners, heaters, stoves, furnaces, water heaters, etc., without any modification to the equipment.

However, a major incompatibility still exists for particular customers who will subsequently compress their gas receipts. These customers include those using NGVs, certain distributed generation equipment, and certain electricity power generating units. The incompatibility arises due to propane's low vapor pressure causing the propane component to drop out of the mix in liquid form as pressure increases when any of these particular pieces of equipment are being used. Since liquids cannot be compressed, the compression equipment can be damaged.

6.2 Propane Storage

In contrast to the mined underground storage caverns utilized by Duke Energy at its Erlanger and East Works sites (and until recently at Dick's Creek), propane is typically stored on site by gas utilities in insulated steel storage tanks. The tanks are either built above ground or are buried slightly below ground for temperature and safety reasons.

6.3 Liquified Natural Gas Plants

6.3.1 Purpose of LNG Facilities

LNG facilities are typically used to provide peaking supplies similar to propane air plants. In general, LNG facilities provide more gas storage than propane air facilities and thus are used in systems that require peaking supplies for more than a few days ; perhaps for a few weeks each winter. LNG plants are used both by distribution/transmission utilities and by major interstate pipelines. Peaking supplies from LNG facilities are much more compatible with natural gas supplies and with the requirements of users that utilize recompression of their gas after purchase (such as NGV markets) than are peaking supplies from propane-air facilities.

6.3.2 Components of LNG Facilities

The LNG plants typically constructed for gas utilities are of two different types: either a satellite plant or a full-service plant.

Full-service LNG plants contain:

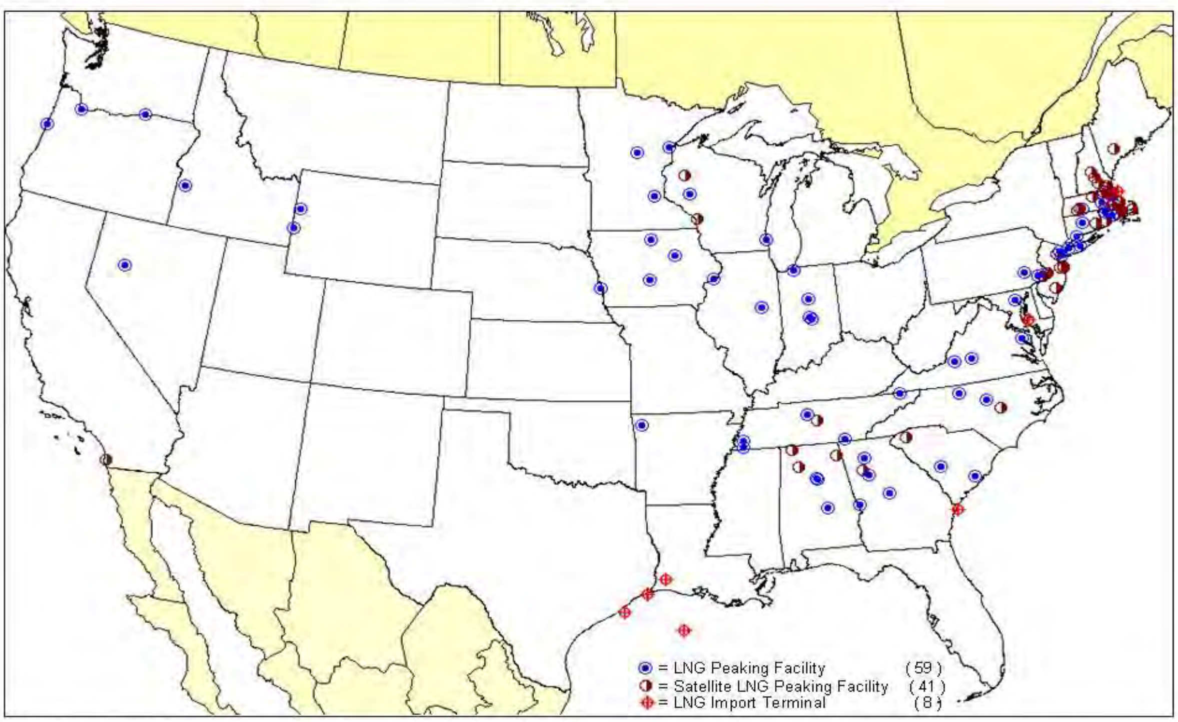
1) Liquifaction Facilities where natural gas is converted to a liquid during non-peak periods of the year by lowering its temperature,
2) Storage Facilities where the liquid gas is stored for usage during peak periods, and
3) Vaporization Facilities where the liquid is heated and sent into the distribution system to bolster supplies during peak periods.

Satellite plants contain only storage and vaporization facilities. Therefore the liquid gas must either be brought into the plant from a full-service facility owned by the gas utility at a different location, or the liquid must be purchased from a full-service facility owned by an outside company. Additional information regarding LNG facilities is provided in an attached report in Appendix C. This report was prepared for the INGAA Foundation.

6.3.3 Number and Size of U.S. LNG Facilities

The following map indicates the existing gas utility LNG plants in the U.S.:

Figure 49: Map of U.S. LNG Plants

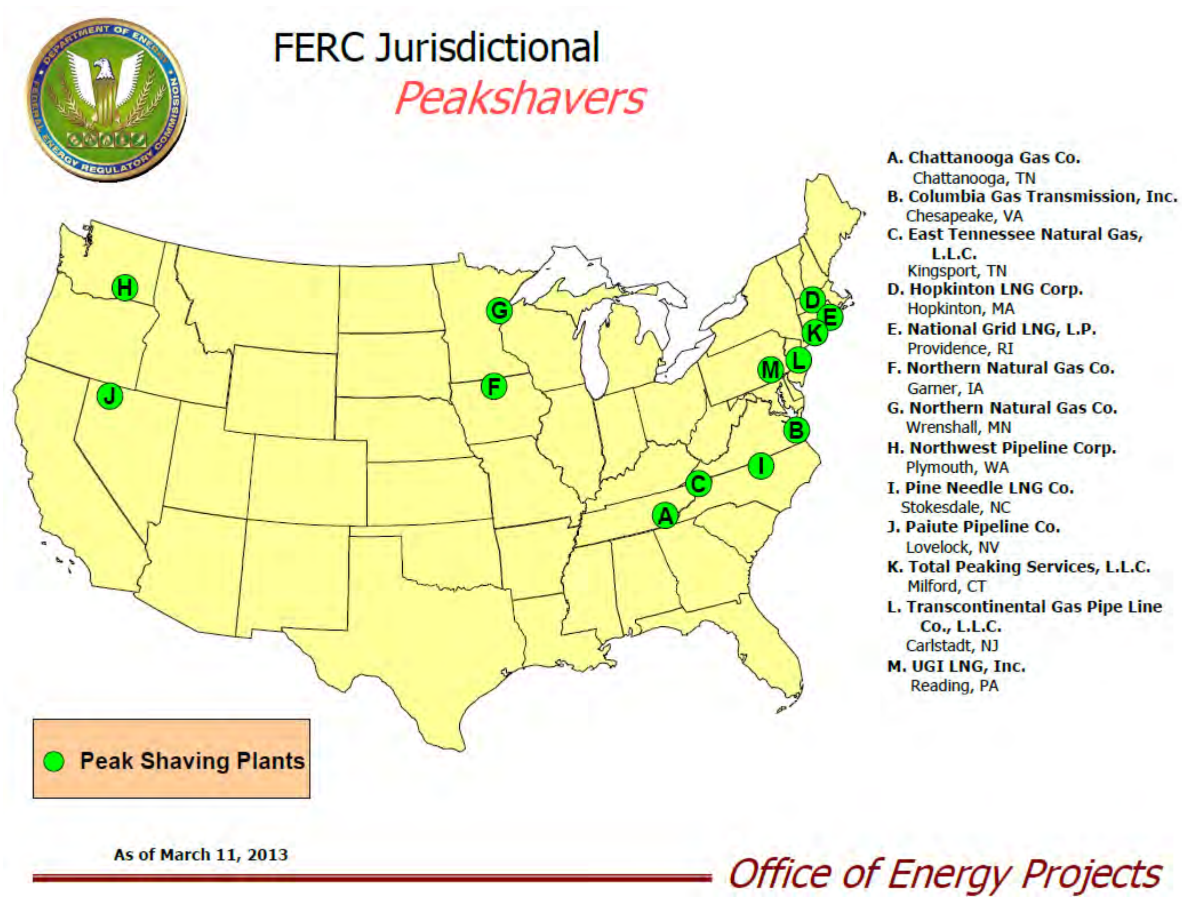


Note: Satellite LNG facilities have no liquefaction facilities. All supplies are transported to the site via tanker truck.
Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division Gas, Gas Transportation Information System, December 2008.

Typical liquefaction capacities of the above facilities fall in the range of 1-20 million scfd. Typical vaporization capacities of the above facilities fall in the range of 75 to 150 million scfd.

LNG facilities are also owned and used by interstate pipelines to manage their ability to provide natural gas during peak periods or during pipeline interruptions. The following map indicates the existing Federal Energy Regulatory Commission (FERC) jurisdictional LNG plants in the U.S.:

Figure 50: Map of U.S. Peakshaving LNG Plants under FERC Jurisdiction



Source: Federal Energy Regulatory Commission

7 Duke Energy's Peak Supply Facilities

7.1 Overall Peak Supply Facilities

To augment natural gas supplies in support of system operations, Duke Energy has operated three propane-air facilities over the past six heating seasons. These facilities are:

1) East Works in Cincinnati, OH
2) Erlanger, KY, and
3) Dick's Creek, OH

The three propane air plants are essentially identical in equipment type and size. They generally can inject propane air into the system as high as 200 to 215 psig, thereby setting the limit to which the immediately connected laterals can be operated. On peak, propane air reaches about 70 percent of the system.

In general propane-air facilities are comprised of three major components, namely 1) propane liquid storage, 2) propane vaporization, and 3) blending of propane with air for injection into the system (i.e. sendout). While Duke Energy has owned and operated the three above identified propane-air plants and two of the storage caverns, the Todhunter cavern, which served the Dick's Creek plant was sold to a third party in 2007. This cavern has experienced containment issues and is no longer in operation.

On Duke Energy's system, peaking facilities provide a dual function:

1) Duke Energy's two remaining propane-air plants operate as standard peaking facilities (referred to as "peakers"), which furnish supply on very high demand days (i.e. peak days). Available pipeline services that offer similar types of on-demand supply for only very short periods, have imbedded demand charges that sometimes render such services uneconomical. In general, short term services result in lower annual load factor usage, expressed as a percentage of average capacity utilization to maximum available capacity. Base load services typically have 100 percent load factor, where the maximum capacity is used every day. For peaking, or no-notice services, the capacity is used only on a few days, and thus have a low load factor, To minimize low load factor service contracts, utilities "peak shave" their supply requirements with lower cost options, such as propane-air, LNG, or storage facilities. However these comparisons are based on newer facilities that do not require large maintenance expenditures. Duke Energy's peaking facilities range from 50 to 65 years in age and now require significant maintenance.

2) Duke Energy's propane air plants also serve as a pressure and a supply boosting operation to supplement gas supplies to certain sections of the service territory where it is not possible to route pipeline supplies on heavy-usage days due to limitations of particular legs of Duke Energy's transmission system. As such, this usage is not an economic decision but an operating necessity. However many new line expansions envisioned in this study would no longer require supplementation of supplies through peaking facilities.

Duke Energy does not currently own any other type of on-system peaking supply, such as LNG or storage. Lummus Consultants believes that both of Duke Energy's current propane air facilities have served a critical role in the provision of peaking and supplementary gas supplies for many decades. Indeed, due to the physical flow limitations of Duke Energy's transmission system during these years, it appears that Duke Energy could not have provided sufficient gas to its customers on peak days nor on days where exceptional operating problems occurred without having these propane air facilities available. At the same time however, the facilities, while generally well maintained, are aged, require additional maintenance expense, and have a number of serious drawbacks including:

- The maximum available injection pressure of about 207 psig at the Erlanger facility limits the use of availability capacity of the transmission lines in the area, predominantly Kentucky. Therefore using the Erlanger plant on peak days is somewhat of a self-defeating measure, since it limits the ability of the transmission system to supply natural gas to that area, which then requires more propane air to be injected.
- The East Works facility is antiquated, employing equipment and containment buildings that are considerably aged and modified over time. For instance one building at East Works was extensively modified in 1960 to house vaporizers and mixing runs.
- The rock-mined caverns are not a standard means of storage for propane for use by gas utilities. The caverns are more than 60 years old. The modern means of storing propane utilizes above-ground (or ground-covered) steel tanks.
- Over the last century, the propane storage caverns and propane-air sites have experienced significant encroachment. In particular, vehicular traffic, which did not exist when the caverns were mined has expanded on nearby streets and river bridges. Barge traffic as well has increased on the Ohio River, which flows very near the propane caverns.
- The underground caverns store tremendous amounts of propane, compared to standard steel tanks. Each cavern stores about eight million gallons of propane (about 200,000 Bbl of working volume), although Duke Energy does not typically fill them completely, it retains a significant amount of propane in them year-round for integrity maintenance purposes. We understand the Dick's Creek cavern, formerly owned by Duke Energy, is no longer operational.
- The East Works storage cavern has recently exhibited a very slight casing leak for the first time. An engineering inspection by Natural Engineering Services, PLLC concluded that although the exact location and source of the leaking propane has not been determined, the leaking propane has now been controlled and is currently being diverted through use of a standard boot seal installed in June, 2014. It is being regularly monitored by Duke.
- Unlike natural gas, which is lighter than air and will quickly dissipate in the event of a leak, propane is heavier than air, and if leaked will seek low lying areas where it can amass and become a much more serious safety hazard.
- The boilers at the Erlanger facility have not been replaced and are now judged by a third party to have about four years of remaining life. The boilers at the East Works were replaced; however the original ones have not been removed.

7.2 East Works Propane Facilities

7.2.1 East Works Site

Duke Energy's Ohio propane facility, East Works, is located along Riverside Avenue (formerly Eastern Avenue) on the east side of Cincinnati. It was constructed during the 1880s on the banks of the Ohio River. The site covers 15.94 acres (6.16 acres in East Parcel; 6.49 acres in Center Parcel; and 3.29 acres in West Parcel), and has been in continuous use by Duke Energy and its predecessor companies for decades.

East Works was originally the site of a manufactured gas plant where gas was produced from coal starting in 1843 before natural gas became available in the region. It reportedly featured a new, low-cost European system of coal carbonization, which helped reduce gas-manufacturing costs. In 1907 the first supply of natural gas was introduced in Cincinnati. Initially limited in supply, natural gas was quickly received with favor, offering a cleaner and safer fuel than manufactured gas with the ability to heat twice as fast at half the price, according to historical records.

Some of the original brick and stone buildings are still standing and have been modified over time to support more current requirements. Portions of the site have been remediated to remove tar products, which were absorbed by the soil during the time of manufactured gas production and storage.

In 1948 CG&E abandoned the mixing of manufactured and natural gas and converted its gas making equipment at the East Works to produce an oil gas that was interchangeable with natural gas.

Below is a current photo of the East Works site as viewed from the river and facing Riverside Ave.

Figure 51: East Gas Works Plant

7.2.2 East Works and Constance Mined Propane Caverns

Duke Energy stores its propane for winter use in two underground caverns located along the Ohio River. The caverns were mined into the blackstone rock layer below the shallower limestone. The caverns are found between 100 feet and 400 feet below ground. They are located very near the Ohio River. Below is a photo depicting miners and their equipment in one of the cavern tunnels at the time the caverns were mined.

Figure 52: Underground Cavern

The storage caverns have served Duke Energy and its predecessors very well for a long period of time. However these caverns are judged by Lummus Consultants to now have a number of questions that should be considered by Duke relating to continuation of their service for a modern gas utility. These include issues of age, congestion from surrounding encroachment, a slight propane leak, limited remaining boiler life, and other issues detailed above in Section 7.1 of this report. Similar to Duke Energy's distribution mains which have recently been replaced due to their age and risk (as recommended by PHMSA and supported by Duke Energy's regulators), these caverns may need to be decommissioned due to their age and risk.

7.3 Erlanger Propane Facilities

Duke Energy constructed and operates its second propane air facility south of the Ohio River near Erlanger, Kentucky. The facility was constructed during the 1950s. Propane storage for this facility is not located on site but is pumped from an underground mined cavern, the Constance Cavern, on the south bank of the river. Below is a recent photo depicting the facilities and control buildings at the Erlanger plant:

Figure 53: Erlanger Plant

The following photo depicts the Erlanger steam boilers that are planned for replacement in about four years:

Figure 54: Erlanger Plant Steam Generators

7.4 Propane Sendout Volumes

The three propane plants (East Works, Erlanger, and Dick's Creek) produced propane-air for a total of 94 days over the past six heating seasons, averaging 15.6 days per year. Together the plants sent out a total of 426,248 Mcf over these six heating seasons, an average of 71,041 Mcf per year. However during the extreme cold experienced in the Cincinnati area in 2014, propane send-out exceeded the *average yearly* output on the following two days:

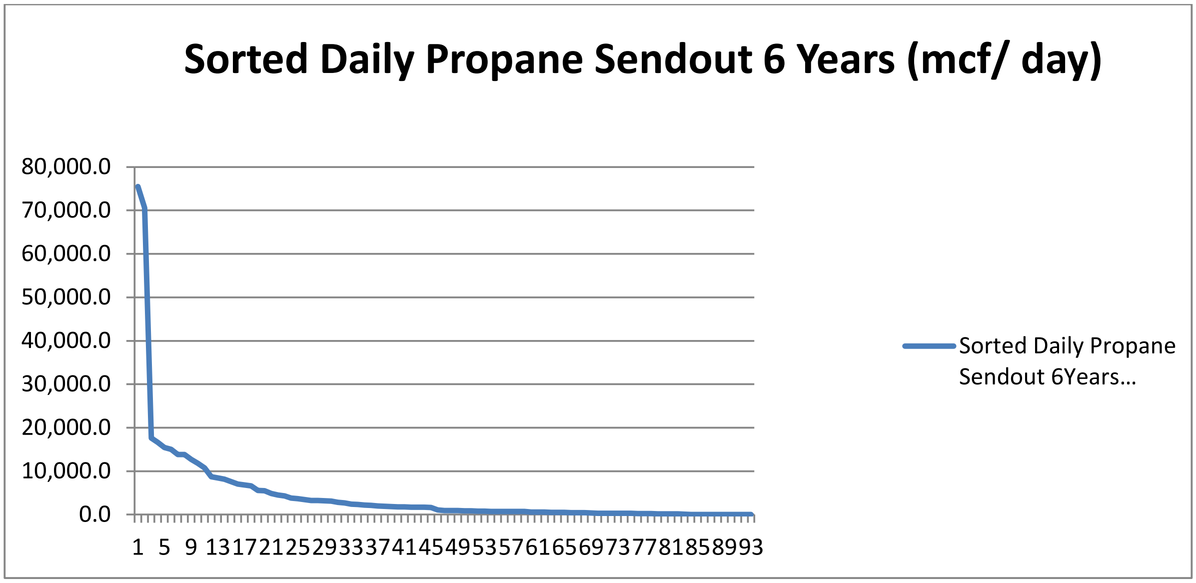
1. January 7, 2014 Propane send-out of 75,507 Mcfd, and
2. January 6, 2014 Propane send-out of 70,582 Mcfd.

The third highest daily propane send-out over these six years occurred on January 23, 2014, amounting to 17,613 Mcf, a substantially lower amount of send-out. On all three peak send-out days, the Dick's Creek facility did not operate since it had been shut-down in 2013. The next section contains a graph illustrating these send-out rates on a sorted load duration basis

7.5 Propane Load Duration Curve

The graph shown below identifies the total daily send-out for Duke Energy's propane-air plants relative to a load duration curve. The horizontal axis indicates propane was sent out on a total of 95 days over the past six years. The send-out volumes are sorted from highest send-out per day to lowest send-out per day:

Figure 55: Duke's Propane-Air Plants Total Daily Sendout



Lummus Consultants notes that only the first few days of very high propane send-out shown in the above chart are of concern when analyzing the most economical way to fulfill peaking needs. Propane send-out for most of the remaining days was required by pressure or flow constraints in Duke Energy's transmission system, rather than by cost considerations. Thus other peaking sources (such as LNG and pipeline contracts) were considered for an economic analysis of alternative ways to provide peaking supplies on only the highest demand days.

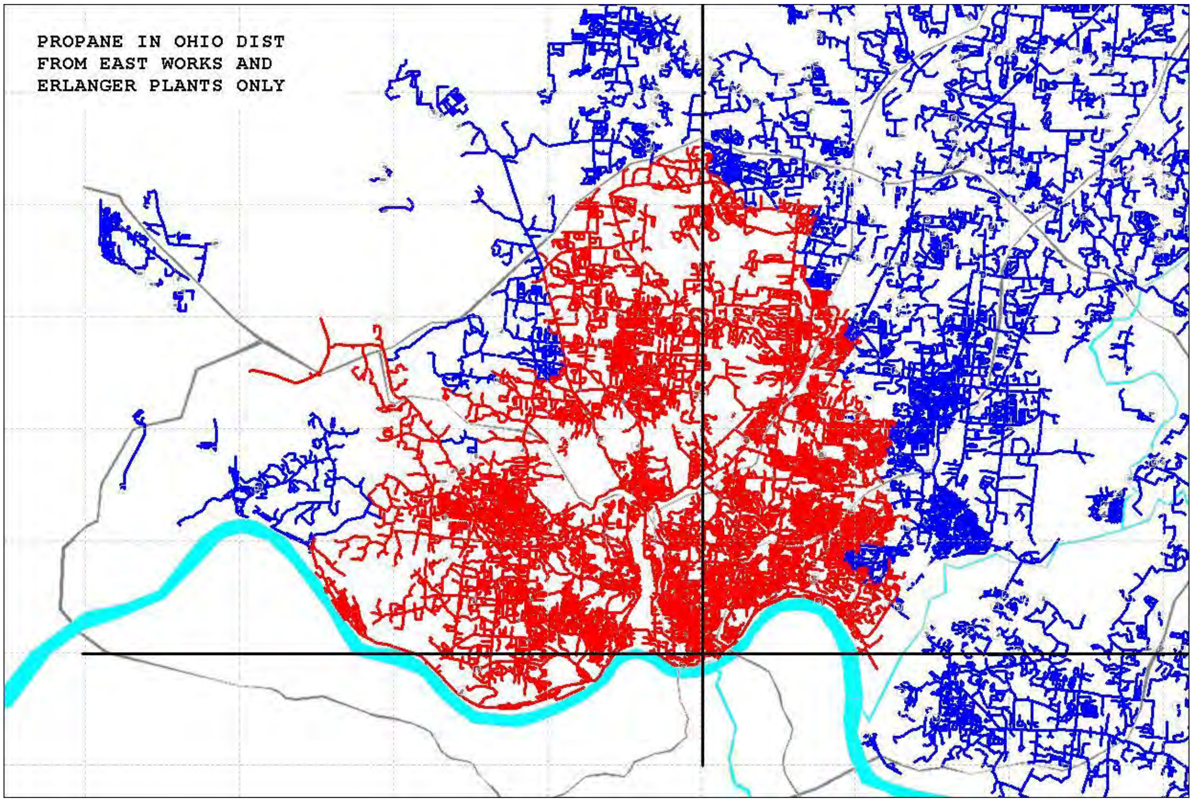
7.6 Extent of Propane Travel Throughout Duke's Service Territory

When the propane air peaking plants are in use, gas supplies containing the propane air can travel extensively throughout Duke Energy's piping systems due to the numerous piping connections depending on the volumes of propane/air sent out.

7.6.1 Extent of Propane Travel Throughout Ohio From East Works & Erlanger Facilities

The following map illustrates in red the maximum potential extent of propane/air throughout Duke Energy's Ohio Distribution system when propane air is being produced at both the East Works and Erlanger facilities:

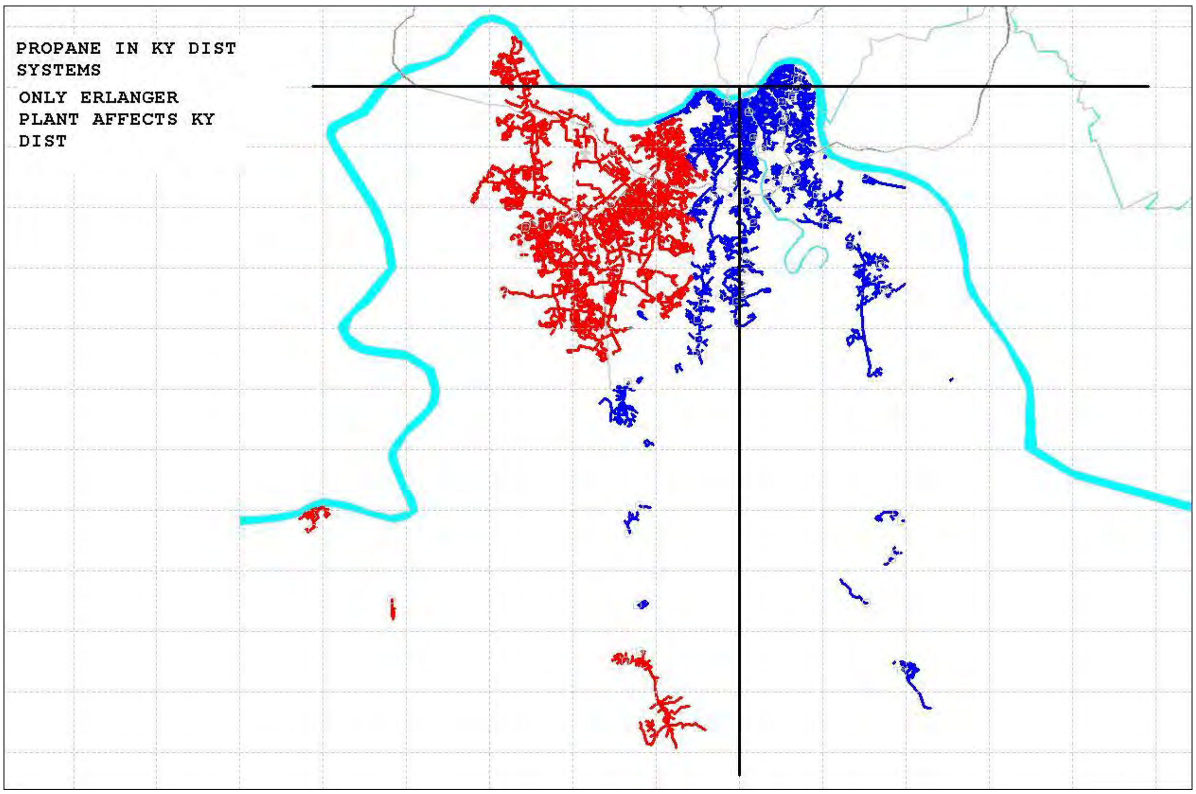
Figure 56: Maximum Extent of Propane Travel in Ohio from East Works and Erlanger



7.6.2 Extent of Propane Travel Throughout Kentucky From Erlanger Facility

The following map illustrates in red the maximum potential extent of propane air throughout Duke Energy's Kentucky Distribution system when propane air is being produced at the Erlanger facility (propane air from East Works does not enter Kentucky):

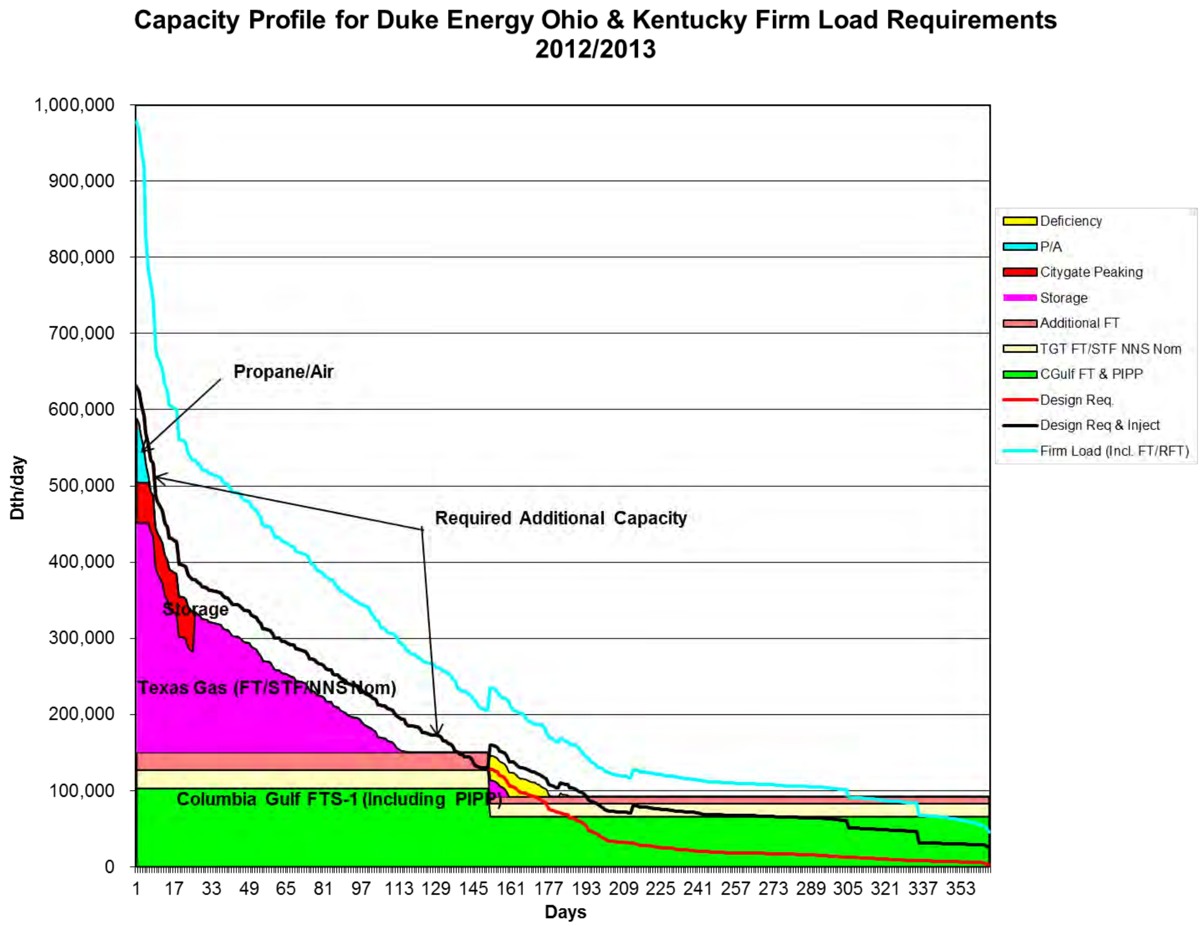
Figure 57: Maximum Extent of Propane Travel in Kentucky from Erlanger



7.7 Firm Requirements Load Duration Curve

The graph below presents Duke Energy's total supply load duration curve for the heating year 2012-2013.

Figure 58: Duke Energy's 2012-2013 Heating Year Total Supply Load Duration Curve



The design requirement for propane air (or an alternative peak-shaving source) is shown in the blue triangle. The maximum daily requirement for peak-shaving is 83,852 Mcfd, with a total heating season requirement of 296,943 Mcf. Peak-shaving is planned to be required on six days during the heating season. These figures would define the peak-shaving requirements, storage capacity, and vaporization capacity required by any source of peak-shaving, such as LNG, or on-system storage.

These figures represent the peaking requirements of Duke Energy for its customers that rely on Duke Energy for gas purchases. They do not include peaking supplies (nor other supplies) required by CHOICE or other transport customers, if any. The total requirement for all customers that use Duke Energy's transportation and distribution system is depicted by the upper blue curve on the graph.

8 System Capital Improvements and Costs

Lummus Consultants has determined through use of Duke Energy's flow model that the following major (in excess of $5Million each) capital improvements will be required during the forthcoming 20-year time period:

Table 17: Expansions and Peaking Capital Expenditures

	EXPANSIONS AND PEAKING CAPITAL EXPENDITURES	ESTIMATED COST ($MM) MINIMUM			ESTIMATED COST ($MM) MAXIMUM		
1	ONE OF 7 RELIABILITY EXPANSION OPTIONS	$	52.2		$	401.6	(1)
2	G7BIGBON CONNECT UL02 TO AM03	$	7.5		$	19.0	
3	GC338 EXTEND C338 FROM BETHEL TO SS00 (UNLESS E-1 EXPANSION ELIMINATES NEED)	$	50.0		$	100.0	(2)
4	POSSIBLY DECOMMISSION BOTH PROPANE FACILITIES AND CAVERNS AFTER ONE RELIABILITY OPTION IS INSTALLED	$	5.0		$	7.0	(3)
	TOTAL 20-YEAR CAPITAL EXPANSION PLAN	**$**	**114.7**		**$**	**527.6**	

NOTES:

(1) Min & Max costs are low and high cost estimates for least expensive (C-1) and most expensive (combined C-2/W-2) options.

(2) GC338 Expansion is still required for all potential new expansions, except possibly not required for expansion E-1.

(3) One time write-down upon abandonment of Erlanger and East Works plants

Shown below is the cost of each of the seven potential new expansion options referred to in the above table that have been advanced by Lummus Consultants as having varying degrees of effectiveness in increasing the flexibility and reliability of Duke Energy's transmission piping system.

Table 18: Costs of Expansion Scenario

Run	Description	Dimensions		Estimated Cost (6)		Flexibility Cost Benefit(1), $1000
		Est Length, mile	Nom Dia, inch	Low, $1000	High, $1000	
Fmax	Foster Flow Maximized	N/A	N/A	Existing System		-
Nmax	Northern Flow Maximized	N/A	N/A	Existing System		-
C-1	24" WW to V-Line	9.8	24	52,181	111,817	20
C-2	36" WW to California	18.7	36			
	16" to V-line	1.6	16			
	totals	20.3		106,078	227,311	340
C-3	C-2 (see above)	20.3	various			
	36" Red Lion to Mason	9.9	36			
	totals	30.2		149,163	319,636	340
W-1	32" Harrison to Anderson Ferry (2)	18.1	32	74,278	159,168	200
W-2	36" Harrison to Miami Ft take-off	7.6	36			
	32" Miami Ft take-off to And. Ferry	10.5	32			
	16" Miami Ft take-off to Miami Ft (3)	3	16			
	totals	21.1		81,349	174,320	200
W-3	32" Fernald to Anderson Ferry	21.6	32	136,438	292,366	200
C-1/W-1	Combined C-1 & W-1 Runs (4)			126,459	270,985	311
C-2/W-2	Combined C-2 & W-2 Runs			187,427	401,631	340
E-1	30" Red Lion to California (5)	43.4	30	128,629	275,633	340

(1) Est by Jeff Kern and does not include transportation customer benefit, which could double given estimate

(2) Requires 500 psig at Harrison; 36-inch line is required for 450 psig at Harrison

(3) Assumes 450 psig at Harrison; serves Miami Ft at 5,000 Mcfh

(4) Harrison requires only 390 psig

(5) Assumes 675 psig at Red Lion

(6) Based on Lummus Consultants Class 5 cost estimate, with Duke refinements resulting in -30/+50% estimate incl. 1.5% inflation over 5 years

9 Recommendations

9.1 System Expansion Recommendations

Lummus Consultants recommends that Duke Energy implement at least one of the seven new pipeline expansions that have been outlined in Chapter 5 of this report. Among some of the considerations, selection should be based on the amount of reliability that each option provides, the flexibility that each option contributes to the capabilities of Duke Energy's transmission system, and upon the estimated cost of each potential expansion. Table 19 is a summary of the expansion options indicating the volume requirements from the gate stations affected.

Table 19: Summary Expansion Results at 42,462 Mcfh System Send-out with no Propane-Air Contribution

Run	Description	New Gate Location	New Gate Volume(1)	Foster Flow Requirement(2)
Fmax	Foster Flow Maximized	N/A	N/A	25,512 Mcfh
Nmax	Northern Flow Maximized	N/A	N/A	25,511 Mcfh
C-1	24" WW to V-Line	Mason	10,663 Mcfh	19,662 Mcfh
C-2	36" WW to California	Mason	29,187 Mcfh	0 Mcfh
C-3	C-2 Run plus 36" Red Lion to Mason	Red Lion	28,547 Mcfh	0 Mcfh
W-1	32" Harrison to Anderson Ferry	Harrison	18,087 Mcfh	9,134 Mcfh
W-2	36"/32" Harrison to Anderson Ferry serving Miami Ft at 5,000 Mcfh(3)	Harrison	20,772 Mcfh	6,628 Mcfh
W-3	32" Fernald to Anderson Ferry	Fernald	18,087 Mcfh	9,134 Mcfh
C-1/W-1	Combined C-1 & W-1 Runs (4)	Mason and Harrison	Mason 10,750 Mcfh Harrison 16,408 Mcfh	1,254 Mcfh
C-2/W-2	Combined C-2 & W-2 Runs	Mason and Harrison	Mason 20,290 Mcfh Harrison 15,000 Mcfh	0 Mcfh
E-1	30" Red Lion to California	Red Lion	25,414 Mcfh	0 Mcfh

(1) New Gate Station Volumes include current station throughput
(2) Volume to meet total system demand of 42,462 Mcfhr with no Propane-air augmentation
(3) Miami Ft volume of 5,000 Mcfh assumed start up only
(4) California flow is 1,140 Mcfh if pressure is lowered to 400 psig

Legend:

Fmax reflects the forced maximum flow from Foster as limited by system capacity
Nmax reflects the forced maximum flow from northern gate stations as limited by system capacity
C-expansions are generally along the center of the system
W-expansions are generally on the West of the system
E-expansions are generally on the East of the system

The selection of an appropriate expansion would necessarily consider numerous aspects, to include not only reliability, flexibility and cost, but also such factors as accessing regional growth, synergies with planned pipeline upgrades, safety (i.e., traversing of HCA), and ROW issues, etc. Table 20 is an example suggestion of how Duke Energy might envision a ranking scheme of the expansion options presented. Duke Energy should find consensus on which ranking categories are relevant and assign ranking weights to each category. Table 20 is only an example of how such a ranking scheme would indicate the relative weight of each option. For the assigned values below, expansion option W-2 would be the preferred choice, with the C-2 option showing a close second preference.

Table 20: Example Expansion Options Selection Ranking

		Expansion Scenario Raw Ranking									
Category		C-1	C-2	C-3	W-1	W-2	W-3	C-1/W-1	E-1	C-2/W-2	Do Nothing
Reliability		1	5	5	3	3	3	4	5	5	0
Cost		4	2	1	3	3	1	2	2	0	5
Constructability		4	3	3	3	3	2	3	1	2	5
Flexibility		1	1	5	2	2	2	2	5	2	0
New Markets		5	5	5	5	5	5	5	5	5	0
Regional Growth		1	3	3	3	4	2	3	4	5	0
Integ./Pipeline Upgrades		3	4	4	3	3	3	5	2	5	0
Total		19	23	26	22	23	18	24	24	24	10

Category	**Weighting Factor**	C-1	C-2	C-3	W-1	W-2	W-3	C-1/W-1	E-1	C-2/W-2	Do Nothing
Reliability	0.2	0.20	1.00	1.00	0.60	0.60	0.60	0.80	1.00	1.00	0.00
Cost	0.4	1.60	0.80	0.40	1.20	1.20	0.40	0.80	0.80	0.00	2.00
Constructability	0.1	0.40	0.30	0.30	0.30	0.30	0.20	0.30	0.10	0.20	0.50
Flexibility	0.05	0.05	0.05	0.25	0.10	0.10	0.10	0.10	0.25	0.10	0.00
New Markets	0.05	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.00
Regional Growth	0.1	0.10	0.30	0.30	0.30	0.40	0.20	0.30	0.40	0.50	0.00
Integ./Pipeline Upgrades	0.1	0.30	0.40	0.40	0.30	0.30	0.30	0.50	0.20	0.50	0.00
Total	1	**2.90**	**3.10**	**2.90**	**3.05**	**3.15**	**2.05**	**3.05**	**3.00**	**2.55**	**2.50**
Overall Rank		**6**	**2**	**7**	**3**	**1**	**10**	**4**	**5**	**8**	**9**

Reliability	The ability to reduce gas throughput at Foster
Cost	Cost effectiveness
Constructability	Difficulty to obtain easement rights or construct pipelines in the proposed corridor
Flexibility	The ability to access multiple suppliers
New Markets	NGV development due to the elimination of P/A plants
Regional Growth	Pipeline provides expansion of gas systems to areas of new growth, power plant usage.
Integ./Pipeline Upgrades	Regulatory Risk - Pipeline option aids addressing TIMP issues/obviates the need for planned pipeline expansions

9.2 Propane Plant Recommendations

Lummus Consultants recommends that Duke Energy should evaluate the phasing out, closing, and decommissioning of both propane air facilities currently operated by Duke Energy (at East Works and at Erlanger). This recommendation includes evaluation of the decommissioning of the underground mined-cavern propane storage facilities as well as the above-ground propane air blending facilities. Lummus Consultants has arrived at this conclusion based on the following reasons, arranged in order of perceived importance:

9.2.1 Decommissioning of Propane Underground Cavern Storage Facilities

- The underground storage caverns, both of which lie close to the Ohio River, have been encroached upon by several types of establishments, creating risks that did not exist when the caverns were constructed. River barge traffic, housing developments, nearby road construction, and river bridges carrying large numbers of vehicles, have all increased during the past 60 years since the cavern construction. These risk exposures are of more concern now due to the increased congestion.
- Lummus Consultants believes that the caverns continue to be used due in part to the grandfathered nature of their construction, operation, and regulation. Construction of these caverns today, under current conditions and regulations, would not be as likely to receive approval from Federal, State, or local regulatory agencies, the Corps of Engineers, local fire departments, etc.
- Pipeline and Hazardous Materials Safety Administration **(**PHMSA) defines high-risk infrastructure as: "High-risk pipeline infrastructure is piping or equipment that is no longer fit for service", and one of its criteria is age. PHMSA has written to regulators encouraging them to support replacement of aged infrastructure through appropriate rate treatment. In a letter to National Association of Regulatory Utility (NARUC)[20], PHMSA stated: "As U.S. Department of Transportation (DOT) and the National Association of Regulatory Utility Commissioners (NARUC) continue to support efforts to accelerate the repair, rehabilitation, and replacement of high-risk **infrastructure** in pipeline systems, we appreciate the NARUC's continued diligence in promoting rate mechanisms that will encourage and will enable pipeline operators to take reasonable measures to repair, rehabilitate or replace high-risk gas pipeline infrastructure."
- The rock-mined storage caverns- now well over 60 years old, are not a standard means of storage for propane. The modern means of storing propane utilizes above-ground (or ground-covered) steel tanks.
- The storage caverns are showing signs that they are near the end of their useful life. The East Gas Works storage cavern has recently exhibited a very slight casing leak for the first time. We understand that the Todhunter Cavern, which serviced Dick's Creek and was owned and operated by Enterprise, is no longer operational because of a storage integrity issue.
- Unlike natural gas, which is lighter than air and will quickly dissipate in the event of a leak, propane is heavier than air, and if leaked will seek low-lying areas where it can amass and become a more serious safety hazard.
- Recent media coverage of earthquake events, such as those in August, 2014 in Napa, CA and a few years ago in San Bruno, CA illustrate the damage that can occur to underground assets of gas utilities with little or no forewarning.

9.2.2 Decommissioning of Propane Air Blending Facilities

- Once one or more of the new expansions recommended above, are installed, there will be sufficient supplies in the Kentucky portion of Duke Energy's service area, to the extent that supplemental peaking supplies from Duke Energy's Erlanger facility, which have historically

[20] http://opsweb.phmsa.dot.gov/pipelineforum/docs/PHMSA%20111011-002%20NARUC.pdf

been required on high-demand days, will no longer be required for purposes of pressure support or additional supply.

- The maximum available propane-air injection pressure of about 207 psig at the Erlanger facility limits the use of available capacity of the AM07 and UL02 transmission lines in Kentucky. These lines have MAOPs of 392 psig and 360 psig, respectively. As such, using the Erlanger facility on peak days is somewhat of a self-defeating practice, since it limits the ability of the transmission system to supply natural gas to that area, which then necessitates the injection of more propane-air.
- Both Kentucky and Ohio State Energy Plans specifically recommend converting state fleet vehicles to be fuelled by CNG. Furthermore, Ohio's 21st Century Energy Policy cites the ability of alternative fuels to have the potential to reduce our reliance on foreign energy sources. The Policy features as one of its ten Pillars "a cooperative effort with other states to develop regional CNG refueling infrastructure and promote the usage of CNG vehicles in Ohio." This agreement was signed by the Governor's Office, PUC of Ohio and Ohio DOT on February 29, 2012. (See Appendix B for a copy of this Ohio Energy Policy). Lummus Consultants understands that a major impediment for Duke Energy in its efforts to advance this policy is the presence of propane in its natural gas deliveries.
- The presence of propane air in Duke Energy's system – even for only a few days a year – is judged to be a major hindrance to Duke's ability to expand its gas business by entering new markets that require complete elimination of propane from the gas stream.
- The East Gas Works propane storage and blending plant, is an outdated facility, employing equipment and containment buildings that are considerably aged and modified.
- The boilers at the Erlanger facility have not been replaced and are now judged by a third party to have about four years of remaining life. The boilers at the East Gas Works were replaced; however the original ones have not been removed.

9.3 New Peaking Option Recommendations

Lummus Consultants points out that even after Duke Energy's current propane-air plants are decommissioned, and an expansion option has been implemented, the system will still require a peaking gas supply. This will not be as a requirement to support the system's flow/pressure operations, as we have established that the system is physically capable of delivering the record peak day volumes without the assistance of propane air, but the new peaking supply will be required to economically serve the low-load factor, seasonal peak demands. The sole requirement for peaking supplies will be due to the economics of fulfilling demand encountered for only a few days when extreme cold weather is experienced. These economics have been compared by Lummus Consultants through analysis of the annual costs of various peaking gas facilities versus the demand charges that would be incurred if interstate contract gas were used in its place.

In terms of the lowest cost option to replace the propane air plants, without consideration of reliability or flexibility improvement, which is the focus of our expansion options, Lummus Consultants considered various alternatives to providing peaking supply, as follows:

- Underground Storage – This option has been studied by others and found to be cost prohibitive in terms locating a suitable depleted gas reservoir that is in close proximity to minimize new pipeline costs; of adequate size and depth to minimize cushion gas and compression capital/operating costs; of suitable condition to minimize new well and gathering infrastructure;

of acceptable integrity to accommodate pressure cycling; etc. Based on the information obtained, this peaking option was ruled out by Lummus Consultants.

- LNG Peaking Facilities – This type of facility is commonly used for peaking service. It requires significant investment capital, technological operations experience, as well as prudent and community-approved siting. It has its place in LDC peaking operations, and for this reason was considered as a peaking alternative.
- Pipeline Peaking Supply – One option to providing pipeline peaking supply considers the implementation of one of the identified system expansion scenarios to enable the receipt of gas from a northern gate station, thereby not relying on Foster for increased volumes on peak day.
- A related pipeline peaking option also considered increased supplies on CGT at Foster, but not in excess of 400 psig, as limited by the supply contract with CGT. In this case compression would be required to boost all supply, not just peaking supply, through Foster to 500 psig. While such an investment was initially shown to be indeed economical, the capacity through CGT cannot be made available. This option was unfortunately dropped due to the unavailability of capacity from CGT .

Table 21 presents comparative costs for the peaking options discussed above:

Table 21: Peaking Options Cost Comparison Summary

	COST COMPARISON OF PEAKING OPTIONS AT DUKE ENERGY ($ Million) (BASIS: 85,000 Dthd Peaking Capacity)					
	CURRENT P-A PLANTS		NEW LNG PLANT (2)		PIPELINE PEAKING SRVC	
COST ELEMENTS	Investment (1)	Annual Cost (1a)(1b)(1c)	Investment (2a)	Annual Cost (2b)	Investment Pipeline (3)	Annual Cost (3a)(3b)
Investment Capital; Annual Levelized Fixed Charge at 12% est	10.1	1.2	136.0	16.3	82.0	9.8
Contract Demand Charge	-	-	-	-	-	1.0
Inventory, Interest on Inventory at 12% est.	5.0	0.6	4.3	0.5	-	-
Annual commodity cost of sendout	-	5.2	-	0.0	-	2.2
O&M (Labor and Materials)	-	1.4	-	0.0	-	-
Utilities, incl. Fuel	-	0.1	-	0.0	-	-
Propane Plant Decomissioning One-Time Avg Cost Write Down (4)	-	-	6.0	-	6.0	-
New Markets Opportunity Cost	-	0.6	-	-	-	-
TOTAL COSTS	**15.1**	**9.1**	**146.3**	**16.8**	**88.0**	**13.0**

(1) Includes $9.1MM Erl vaporizer budget through 2017; EW security project, compressor controls, D-line relo, valve replace; Total 9 MMgal Storage: each
(1a) Estimated cost of Propane sendout prior season as equated to required of pipeline peaking volume at btu ratio of 1.4 propane-air/natural gas
(1b) Labor & Materials estimated by C. Fritsch. Erl electric at $4,055/day, EW at $5,141/day for 7 days of sendout
(1c) New Market Opportunity Cost ranges from $353k in 2021 to $2,003k in 2035 per Lummus Demand study
(2) Rough order of magnitude estimate as per CBI business development for 1Bcf storage, 85MMcfd sendout and 5MMcfd liquefaction; incl balance of plant
(2a) Assumes Inventory stored 90% of 1,062,500 dth at $4.50/MMBtu, augmented by winter liquefaction
(2b) Assumes sendout gas cost of $4.5/MMBtu
(3) Estimated System Investment of average high and low cost, Scenario C-1
(3a) Estimated winter 25-day supply of 2,125,000 dth; Pipeline Demand Charge estimated by J. Kern for 2014, to range from $0.6 to $1.4 million
(3b) Cost of gas calculated by J. Kern for 2014 sendout at Lebanon price average $7.1 per MMbtu equated to Propane sendout volume
(4) Estimated at $5 to $7 million

Annual costs for the options shown in the previous table indicate that, while the economics favor the continued use of the propane plants for peaking service, the long term continued use of these plants is not recommended, as discussed in this report. Taking into consideration meaningful factors that affect a viable and robust operation, the "do nothing" option of continued propane use for peaking and operational support, is seen as low ranking among various alternatives.

Long term operations for peaking supplies and enhanced overall reliability, flexibility and market growth, favor the use of short-term (e.g. 25-day) interstate supply contracts once Duke Energy implements one of the nine new expansion options that will permit accessing these types of firm supplies at locations other than through Foster. The least cost meaningful option to replace the propane air plants is shown to be through implementation of a system expansion accessing one or more of the northern gate stations. The cost for this option assumes the implementation of the C-1 Expansion. Further, judged on a ranking scale that considers, in addition to cost, various other important factors, such as reliability, flexibility, constructability, and so forth, the C-1 Expansion option would not likely be as highly ranked as other expansion options, as exemplified in this report.

APPENDIX A

List of Documents Reviewed

APPENDIX B

OHIO's 21st Century Energy Policy

- Mid-Biennium Review

Copy Available at:

http://development.ohio.gov/files/bs/OhioEnergyPolicy.pdf

APPENDIX C

The Use of Liquefied Natural Gas For Peaking Service

- Report Prepared for the INGAA Foundation, Inc.

Copy Available at:

http://www.ingaa.org/file.aspx?id=21698

APPENDIX D

Lummus Consultants Expansion Pipelines

Class 5 Cost Estimates

Headquarters:

Two Riverway, Suite 1300
Houston, TX 77056-2059

Telephone: 281.368.3000
Fax: 281.368.4488

Issuing Office:

150 Royall Street
Canton, MA 02021-1030

Telephone: 617.589.2000
Fax: 617.589.1372

Other Offices:

Centennial, CO
Dubai, UAE
Milton Keynes, UK
Singapore

LUMMUS CONSULTANTS
INTERNATIONAL

STAFF-DR-01-002

REQUEST:

Refer to the Application, paragraphs 5 and 9.

a. State when Duke Kentucky and Duke Energy Ohio, Inc. (Duke Ohio) determined that the Erlanger Cavern was nearing the end of its useful life and should be retired.

b. Describe Duke Ohio's retirement plan, including any necessary regulatory approvals, for the Erlanger Cavern and similar facilities.

c. Explain the ownership arrangement for the Erlanger Cavern (e.g., Duke Ohio and Duke Kentucky jointly own the facility; Duke Ohio solely owns the facility and allocates plant or expenses to Duke Kentucky, etc.).

RESPONSE:

a. Duke Energy Kentucky and Duke Energy Ohio began evaluating the useful lives of their respective propane caverns following the failure of the Enterprise Products Todhunter Cavern in 2012. Duke Energy Kentucky's Erlanger propane cavern and Duke Energy Ohio's East Works propane cavern are of a similar vintage and design to that of the Todhunter Cavern. In 2015, the companies commissioned a report by Lummus Consultants International to analyze the company's natural gas delivery system. As part of that report, among other things, it was recommended that a replacement for these caverns be developed. Duke Energy Ohio sought approval for its Central Corridor Pipeline (CCP) with the Ohio Power Siting Board (OPSB) in 2016, which was approved in late 2019, with construction commencing in 2020. The CCP project was subject to rehearing and then Court appeals. The Ohio Supreme Court affirmed the OPSB's decision in 2021. The CCP is scheduled to fully be placed in-service in early 2022, making the actual retirement possible in 2022.

b. Duke Energy Ohio's retirement plan is the same as Duke Energy Kentucky's retirement plan. After the winter of 2021-2022 and the Central Corridor pipeline is placed in service, the caverns will be depleted of any remaining propane and retired. Duke Energy Ohio has similarly sought approval for accounting deferrals to address the accounting issues and abandonment of its propane-related facilities in order to accomplish retirement. Duke Energy Ohio filed its accounting request on October 7, 2021 in Case No. 21-986-GA-ABN and Case No. 21-1035-GA-AAM. The request is still pending before the Public Utilities Commission of Ohio. A link to that filing can be found here:

https://dis.puc.state.oh.us/CaseRecord.aspx?CaseNo=21-986&x=0&y=0

c. Erlanger Cavern is a fully owned asset of Duke Energy Kentucky and Duke Energy Kentucky allocates plant and expenses to Duke Energy Ohio.

PERSON RESPONSIBLE: Brian Weisker

STAFF-DR-01-003

REQUEST:

Refer to the Application, paragraphs 6–8.

a. Provide the peak capacity currently provided by the Erlanger Cavern.

b. Provide the amount of additional capacity Duke Kentucky anticipates will become available through the KOT Pipeline/southern pipelines when the Central Corridor Pipeline is placed in service.

c. Provide an estimate of the number of operating days that the Erlanger Cavern's capacity provides to Duke Kentucky at full capacity.

d. Explain if the Erlanger Cavern can or is used to hedge against short-term high gas prices.

e. If applicable, explain whether the closure of the Erlanger Cavern (and consequently the loss of the ability to price hedge) would leave Duke Kentucky at risk to short-term high gas prices.

RESPONSE:

a. The Erlanger Cavern provides 25,060 dekatherms per day of peaking capacity for Duke Energy Kentucky.

b. The Central Corridor Pipeline will facilitate the retirement of the Erlanger Propane Plant which will allow for the physical redirection of approximately 26,000 dekatherms per day of existing KOT capacity into the Duke Energy Kentucky system.

c. Duke Energy Kentucky plans for 7 days at 25,060 dekatherms per day of peaking capacity from Erlanger.

d. The Erlanger Cavern can occasionally be used to protect against short-term high gas prices to the extent operationally feasible. Duke Energy Kentucky's System Planning and Gas Control typically determine when propane can operationally be used to meet demand based on Duke Energy Kentucky system pressures, and this may not always coincide with when gas prices spike.

e. The closure of the Erlanger Cavern would not leave Duke Energy Kentucky at a high level of risk to short term high gas prices because the Erlanger Cavern can only occasionally be used to hedge against short term high gas prices to the extent operationally feasible. Duke Energy Kentucky makes every effort to utilize their Columbia Gas Firm Storage Service to minimize the amount of incremental daily supply being purchased to the extent operationally feasible when gas prices spike. In its Order dated March 27, 2015, in Case No 2015-00025, the Commission denied the Company's request to continue its natural gas price hedging program and directed Duke Energy Kentucky to "…cease hedging activities as of the date of this Order."

PERSON RESPONSIBLE: Sarah Stabley

STAFF-DR-01-004

REQUEST:

Refer to the Application, paragraphs 13–14.

a. Confirm that Duke Ohio received approval to construct the Central Corridor Extension on November 21, 2019, and that construction began on March 1, 2021. If this cannot be confirmed, provide the correct dates of the approval and the commencement of construction activities.

b. Confirm that Duke Ohio planned to begin the decommissioning process for the Erlanger Cavern after the winter of 2020-2021. If confirmed, state when this plan was delayed and describe the precipitating event.

c. State whether any event or circumstance other than Duke Ohio's plans to construct the Central Corridor Extension motivated Duke Kentucky's decision to retire the Erlanger Cavern. If so, provide a timeline of those events or circumstances.

d. Explain whether Duke Kentucky separately evaluated any construction project or other method of procuring necessary peak capacity to facilitate the retirement of the Erlanger Cavern. If so, provide the alternatives evaluated. If not, explain why not.

RESPONSE:

a. Pre-construction activities (e.g. easement acquisition, local permitting, etc.,) began in 2020 following project approval. Actual construction commenced March 1, 2021.

b. Incorrect, Duke Energy Kentucky has always planned to retire the Erlanger Cavern after the completion and in-service of the Central Corridor Pipeline.

c. The need for the Central Corridor Pipeline and the plans to retire the Erlanger Cavern are intertwined. Duke Energy's vision for the Central Corridor Pipeline was to both provide capacity for new customers and to replace the capacity of the existing propane caverns. The Erlanger Propane Cavern was constructed in the early 1960's and cannot be upgraded or maintained, however, the cavern pressure is continuously monitored.

d. Duke Energy Kentucky did not separately evaluate other capital construction projects to procure replacement peak capacity. Duke Energy Ohio determined that its Central Corridor Pipeline was the optimal system infrastructure project to meet its supply needs and that enabled the retirement of East Works and coincidentally, the Erlanger Cavern. Duke Energy Ohio evaluated multiple routes to meet its needs. Duke Energy Ohio's Central Corridor Pipeline project enables Duke Energy Kentucky to retire its Erlanger Cavern and related facilities without needing to undertake its own capital-construction project to replace the capacity because Duke Energy Ohio will no longer need to utilize capacity on the KO Transmission System. Duke Energy Kentucky will be able to utilize capacity on the KO Transmission System to serve customers in Kentucky after Erlanger is retired.

PERSON RESPONSIBLE: Brian Weisker
Adam Long

Duke Energy Kentucky
Case No. 2021-00405
STAFF First Set Data Requests
Date Received: November 19, 2021

STAFF-DR-01-005

REQUEST:

Refer to the Application, paragraphs 15 and 19.

a. Quantify the Operations and Maintenance savings that are expected to result from the closure of the Erlanger Cavern.

b. Provide all amounts currently recovered in Duke Kentucky's base rates related to the Erlanger Cavern and its operation.

c. Provide all amounts related to the Erlanger Cavern and its operation included in Duke Kentucky's base rates as requested in Case No. 2021-00190.[2] If any of these amounts are impacted by the Joint Stipulation and Recommendation filed on October 8, 2021, separately identify that impact.

RESPONSE:

a. Approximately $700,000 of Operations and Maintenance savings are expected for Duke Energy Kentucky with the closure of the Erlanger Cavern and Propane Facility.

b. Please see STAFF-DR-01-005 Attachment for the amounts included in base rates per Case No. 2018-000261.

[2] Case No. 2021-00190, *Electronic Application of Duke Energy Kentucky, Inc. for: 1) An Adjustment of the Natural Gas Rates; 2) Approval of New Tariffs, and 3) All Other Required Approvals, Waivers, and Relief* (filed June 1, 2021).

c. Please see STAFF-DR-01-005 Attachment for the amounts included in base rates as requested in Case No. 2021-00190 and the amounts impacted by the Joint Stipulation and Recommendation filed on October 8, 2021.

PERSON RESPONSIBLE: Brian Weisker – a.
Sarah Lawler – b., c.

DUKE ENERGY KENTUCKY, INC.
Gas Production Facilities
Estimated Revenue Requirement

			Case No. 2018-00261	Case No. 2021-00190	
Line	**Description**	**Source**	**Current**	**As Filed**	**Joint Stipulation**
1	Gross Plant [(a)]	Sch B-2.1 Adj Jurisdiction	$ 2,799,608	$ 4,625,622	$ 4,625,622
2	Accumulated Depreciation [(a)]	Sch B-3 Adjusted Jurisdiction	(1,634,598)	(2,553,891)	(2,553,891)
3	Net Production Plant in Service		$ 1,165,010	$ 2,071,731	$ 2,071,731
4	Accum Def Income Taxes on Plant	WPD-2.19a	$ (15,418)	$ (25,621)	$ (25,621)
5	Gas Enricher Liquids	Sch B-5	$ 1,284,114	$ 1,785,156	$ 1,785,156
6	Rate Base		$ 2,433,706	$ 3,831,266	$ 3,831,266
7	Return on Rate Base (Pre-Tax %)	Sch. J-1, Forecasted	8.72% (b)	8.81% (c)	8.16% (d)
8	Return on Rate Base (Pre-Tax)		$ 212,219	$ 337,535	$ 312,631
9	Production Operating Expense	Sch. C-2.1, WPD-2.19c	$ 344,563	$ 708,942	$ 708,942
10	Depreciation Expense	Sch. B-3.2, page 1	$ 217,881	$ 333,766	$ 333,766
11	Annualized Property Tax Expense [(e)]	Sch. B-1, Sch. C-2.1	$ 9,903	$ 14,916	$ 14,916
12	Revenue Requirement (Lines 8 - 11)		$ 784,566	$ 1,395,159	$ 1,370,255

Assumptions:
[(a)] 13 month average.
[(b)] Weighted-Average Cost of Capital, with ROE at 9.7%, grossed up for 21% FIT rate.
[(c)] Weighted-Average Cost of Capital (As Filed), with ROE at 10.3%, grossed up for 21% FIT rate.
[(d)] Weighted-Average Cost of Capital (per Settlement), with ROE at 9.375%, grossed up for 21% FIT rate.
[(e)] Derived from test year property taxes divided by test year net plant multiplied by the Net Production Plant in Service.

Duke Energy Kentucky
Case No. 2021-00405
STAFF First Set Data Requests
Date Received: November 19, 2021

STAFF-DR-01-006

REQUEST:

Refer to the Application, paragraph 17. Explain how the estimated 500,000 gallons of propane to remain in the Erlanger Cavern will be removed for decommissioning and Duke Kentucky's plans for that propane.

RESPONSE:

The Company anticipates flaring off any residual propane that cannot be recovered from the cavern for customer usage, during the cavern decommissioning process.

PERSON RESPONSIBLE: Brian Weisker

STAFF-DR-01-007

REQUEST:

Refer to the Application, paragraph 18.

a. Explain how Duke Kentucky currently includes propane in its Gas Cost Adjustment Rider (GCA).

b. Explain why Duke Kentucky proposes to include the propane in its GCA at the lower of the weighted average cost of the propane inventory or the weighted average cost of gas for Duke Kentucky's supply and storage withdrawals at the Citygate for the month that the propane was burned.

c. Explain how Duke Kentucky procures propane for the Erlanger Cavern.

d. Provide the estimated date that Duke Kentucky will cease procuring propane.

e. Explain whether Duke Kentucky has considered selling any propane not necessary for system reliability at wholesale. If not, explain why not.

RESPONSE:

a. Propane is included in the Gas Cost Adjustment (GCA) Clause through both the Expected Gas Cost (EGC) component and the Actual Adjustment (AA). The EGC represents the estimated quarterly average cost of gas supplies including propane. The AA compensates for any previous over or under collections of gas cost experienced, including propane, for the quarter and is amortized over a 12-month period.

b. Duke Energy Kentucky proposed to include the propane at the lower of the weighted average cost of the propane inventory or the weighted average cost of gas at the Citygate for the month of flow to alleviate customers of the costs associated with potential higher priced propane verses the cost of natural gas or potential higher priced gas verses weighted average cost of the propane inventory. Given that the Company is primarily running the propane through the system in order to decommission the plant and not for system needs, the Company believes this to be the appropriate approach.

c. Duke Energy Kentucky procured propane for the Erlanger Cavern through an RFP process to determine the lowest cost propane being delivered by trucks.

d. Duke Energy Kentucky ceased procuring propane for the Erlanger Cavern on October 17, 2019.

e. Duke Energy Kentucky evaluated two scenarios for depleting propane inventory. The first was to run the propane into the system on days it operationally could and the second was to sell the propane wholesale and truck it out of the caverns. Duke Energy Kentucky arrived at a cost of approximately $1.3 million to run it into the system verses a cost of approximately $1.6 million to sell it wholesale and truck it out. The timing of trucking the propane out was also problematic as it would take approximately eight months to deplete the inventory as well as costing approximately $500,000 to build infrastructure to allow it to be trucked out. Therefore, Duke Energy Kentucky proposed to deplete the propane inventory by running it into the system when operationally feasible.

PERSON RESPONSIBLE: Sarah Stabley

Duke Energy Kentucky
Case No. 2021-00405
STAFF First Set Data Requests
Date Received: November 19, 2021

STAFF-DR-01-008

REQUEST:

Refer to the Application, paragraphs 19 and 24. Confirm that Duke Kentucky proposes to begin amortizing the proposed regulatory asset and recovering in rates at the same level as the expenses currently associated with the Erlanger Cavern. If this cannot be confirmed, explain. If confirmed, explain Duke Kentucky's contention that recovery of deferred costs will be addressed in a separate proceeding.

RESPONSE:

Confirmed as it relates to the NBV of the assets discussed in paragraph 19 and 21 of the application. Amortizing these costs in the proposed regulatory asset at the same level as the expenses currently associated with the Erlanger Cavern allows the Company to continue amortizing at the same rate that was approved in the Company's most current natural gas base rate case proceeding and the natural gas base rate case proceeding currently pending before the Commission. If that amortization period needed to change in the future, the Company would propose that change in a future base rate case proceeding. For the propane inventory and the decommissioning costs discussed in paragraphs 17, 18 and 20, the Company proposes that these costs be classified as a regulatory asset and the recovery of these costs will be addressed in a future natural gas base rate case proceeding.

PERSON RESPONSIBLE: Sarah E. Lawler

STAFF-DR-01-009

REQUEST:

Refer to the Application, paragraphs 19 and 26. Explain in detail why Duke Kentucky requests an order by December 31, 2021, given the March 31, 2022 planned retirement date for the Erlanger Cavern.

RESPONSE:

The triggering event to record journal entries associated with the propane inventory portion of the regulatory asset request is tied to the completion and in-service date of the Central Corridor Pipeline Project. At the time the Company filed this application with the Commission, the planned in-service date of the Central Corridor Pipeline Project was end of December 2021. Since then, due to working through issues with local communities and other unforeseen circumstances, the pipeline is now planned to be in-service in early February of 2022. Therefore, the need for an expedited order by year end 2021 is no longer necessary. The journal entries associated with the write-off of the remaining NBV of the assets and the decommissioning costs themselves were always estimated to occur in 2022 when that decommissioning begins.

PERSON RESPONSIBLE: Bryan Manges
Brian Weisker

Duke Energy Kentucky
Case No. 2021-00405
STAFF First Set Data Requests
Date Received: November 19, 2021

STAFF-DR-01-010

REQUEST:

Refer to the Application, paragraphs 20 and 21. Explain why there is such a large difference in the cost of removal recovered in depreciation rates and the estimated decommissioning costs.

RESPONSE:

The depreciation studies conducted by third parties incorporate the estimated decommissioning costs from the most recent decommissioning cost study, into the cost of removal component of the depreciation rate. The cost of removal recovered accumulates slowly over time through the depreciation rates. Additionally, the total estimated costs for cavern closure have risen since the time the decommissioning study was performed.

PERSON RESPONSIBLE: David Raiford
Brian Weisker