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The Duke Energy Indiana
2013 Integrated Resource Plan

Public Version

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Volume 1

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Integrated Resource Plan – Abbreviations

Activated Carbon Injection	ACI
American Clean Energy and Security Act	ACES
Architecture and Engineering	A&E
Auction Clearing Price	ACP
Behind the Meter Generation	BTMG
Best Available Control Technology	BACT
Calcium Bromide	$CaBr_2$
Carbon Capture and Storage	CCS
Carbon Dioxide	CO_2
Certificate of Public Convenience and Necessity	CPCN
Clean Air Act	CAA
Clean Air Act Amendments	CAAA
Clean Air Interstate Rule	CAIR
Clean Air Mercury Rule	CAMR
Clean Air Transport Rule	CATR
Clean Energy Legislation	CEL
Coal Combustion Residuals	CCR
Combined Cycle (natural gas-fired)	CC
Combustion Turbine (natural gas-fired)	CT
Community Energy Storage	CES
Compact Fluorescent Light bulbs	CFL
Compressed Air Energy Storage	CAES
Consumer Price Index	CPI
Cross State Air Pollution Rule	CSAPR
Demand Response	DR
Demand Side Management	DSM
Duke Energy Indiana	Company
Effluent Limitation Guidelines	ELG
Electric Generating Unit	EGU
Electric Power Research Institute	EPRI
Electronically Commutated Fan Motors	ECM
Energy Efficiency	EE
Environmental Protection Agency	EPA
Equivalent Forced Outage Rate Excluding Events Outside of Management Control	$XEFOR_d$
Federal Energy Regulatory Commission	FERC
Fixed Resource Adequacy Plan	FRAP
Flue Gas Desulphurization	FGD
Generating Availability Data System	GADS
Gigawatt-hours	GWh
Greenhouse Gas	GHG
Hazardous Air Pollutant	HAP
Heat Recovery Steam Generator	HRSG
Heating, Ventilation and Air Conditioning	HVAC
High Load Factor	HLF
Indiana	IN

Indiana Department of Environmental Management	IDEM
Indiana Municipal Power Agency	IMPA
Indiana Utility Regulatory Commission	IURC
Installed Capacity	ICAP
Integrated Gasification Combined Cycle	IGCC
Integrated Resource Plan	IRP
Joint Transmission System	JTS
Kilowatt	kW
Kilowatt-hours	kWh
Load Serving Entity	LSE
Load, Capacity, and Reserve Margin Table	LCR Table
Loss of Load Expectation	LOLE
Low Load Factor	LLF
Low NO_x Burners	LNB
Maximum Achievable Control Technology	MACT
Maximum Net Dependable Capacity	MNDC
Mega Volt-Amps Reactive	MVAR
Megawatt	MW
Megawatt-hours	MWh
Mercury and Air Toxics Standard	MATS
Midcontinent Independent System Operator, Inc.	MISO
Millions of British Thermal Units	MMBtu
MISO Transmission Expansion Planning	MTEP
National Ambient Air Quality Standards	NAAQS
National Energy Technology Laboratory	NETL
National Oceanic and Atmospheric Administration	NOAA
National Pollutant Discharge Elimination System	NPDES
Net Present Value	NPV
New Source Performance Standard	NSPS
New Source Review	NSR
Nitrogen Oxide	NO_x
North American Industry Classification System	NAICS
North Carolina/South Carolina	NC/SC
Nuclear Regulatory Commission	NRC
Ohio/Kentucky	OH/KY
Operation and Maintenance Costs	O&M
Other Public Authorities	OPA
Particulate Matter	PM
Parts Per Billion	PPB
Personalized Energy Report	PER
Planning Reserve Margin	PRM
Planning Resource Margin Requirement	PRMR
Planning Resources Auction	PRA
Power Purchase Agreement	PPA
Present Value Revenue Requirements	PVRR
Prevention of Significant Deterioration	PSD
Pulverized Coal	PC
Ratepayer Impact Measure	RIM
Regional Transmission Organization	RTO
Reliability*First* Corporation	RFC

Renewable Energy Certificates	REC
Renewable Energy Portfolio Standard	REPS
Research, Development and Delivery	RD&D
Resource Conservation Recovery Act	RCRA
Selective Catalytic Reduction	SCR
Selective Non-Catalytic Reduction	SNCR
Short Term Implementation Plan	STIP
Small Modular Reactor	SMU
State Implementation Plan	SIP
State Utility Forecasting Group	SUFG
Sulfur Dioxide	SO_2
System Optimizer	SO
Technology Assessment Guide	TAG
Third Party Administrator	TPA
Total Resource Cost	TRC
Unforced Capacity	UCAP
Utility Cost Test	UCT
Volt-Amps Reactive	VAR
Wabash Valley Power Association, Inc.	WVPA
Zonal Resource Credit	ZRC

1. EXECUTIVE SUMMARY

A. OVERVIEW

Duke Energy Indiana (Company) is Indiana's largest electric utility, serving approximately 790,000 electric customers in 69 of Indiana's 92 counties covering North Central, Central, and Southern Indiana. Its service area spans 22,000 square miles and includes cities such as Bloomington, Terre Haute, and Lafayette, and parts of the suburban areas near Indianapolis; Louisville, Kentucky; and Cincinnati, Ohio.

The Company has a legal obligation and a corporate commitment to reliably and economically meet the energy needs of its customers. Planning and analysis helps the Company achieve this commitment to customers. Duke Energy Indiana utilizes a resource planning process to identify the best options to serve customers' energy and capacity needs in the future, incorporating both quantitative analysis and qualitative considerations. For example, quantitative analysis provides insights into future risks and uncertainties associated with the load forecast, fuel and energy costs, and renewable energy resource options. Qualitative perspectives, such as the importance of fuel diversity, the Company's environmental profile, and the stage of technology deployment are also important factors to consider as long-term decisions are made regarding new resources. The end result is a resource plan that serves as an important tool to guide the Company in making business decisions to meet customers' near-term and long-term energy needs.

The overall objective of the resource planning process is to develop a robust and reliable economic strategy for meeting the needs of customers in a dynamic and uncertain environment. Uncertainty is a critical concern and plays a significant role in the planning process when dealing with emerging environmental regulations, load growth or decline, and fuel and power prices.

Major changes in the 2013 Integrated Resource Plan (IRP or the Plan) from the 2011 IRP are:

- USE OF THREE DISCRETE AND INTERNALLY CONSISTENT SCENARIOS
  The 2013 IRP features the inclusion of three discrete and internally consistent scenarios that add to the richness of the analysis. This is done in two ways: first, the three scenarios cover a wider range of possible futures; and second, the macro-economic modeling for each scenario

was done by a consulting firm using a suite of equilibrium models that defined a set of internally consistent assumptions. The primary distinction between the three scenarios is the level of environmental legislation and regulation. Each scenario also features gas and coal fuel forecasts consistent with that scenario. The three scenarios are:

(1) Low Regulation Scenario

(2) Reference Scenario

(3) Environmental Focus Scenario

- COMPLIANCE WITH NEW EPA REGULATIONS

The United States Environmental Protection Agency's (EPA) Mercury and Air Toxics Standard (MATS) rule finalized in February 2012 created emission limits for hazardous air pollutants (HAPs), including mercury, acid gases, and other metals from coal-fired and oil-fired power plants. The initial compliance date for the rule is April 16, 2015. This is expected to result in the retirement of Wabash River Units 2-5 (350 MW) by the compliance date due to the environmental compliance investments that would otherwise be required. Additional emerging environmental regulations that will impact the Company's retirement decisions include new water quality standards, fish impingement and entrainment standards, the Coal Combustion Residuals (CCR) rule and the new Sulfur Dioxide (SO_2), Particulate Matter (PM) and Ozone National Ambient Air Quality Standards (NAAQS).

Other than MATS, little more is known at this time about these pending or proposed rules than was known during the development of the 2011 IRP. The balance of all of the assumptions for the compliance analyses were reviewed and updated where necessary to coincide with the other assumptions used for the development of this IRP.

As the rules are proposed or finalized in 2013 and 2014, the Company will develop a detailed strategy and seek the necessary regulatory approvals.

- WABASH RIVER UNIT 6 GAS CONVERSION

Due to investments that would be necessary to comply with MATS, Wabash River Unit 6 cannot cost-effectively continue to operate as a coal-fired unit beyond the MATS compliance date. Preliminary analyses indicate it may be cost-effective to convert the unit to natural gas. The Company is benchmarking the cost effectiveness of gas conversion against the results of a request for proposals (RFP) solicitation that was issued in mid-2013. The results of that analysis will be used to make a final decision about the gas conversion and will be reflected in the 2015 IRP.

- DIFFERENT ENERGY EFFICIENCY SCENARIO PROJECTIONS

  Each scenario includes different assumptions for the amount and timing of levels of Energy Efficiency (EE) consistent with the theme of that scenario. In the Low Regulation Scenario, it is assumed that EE programs are not adopted as quickly as called for by the state mandate but that the mandated level of 11.9% is achieved by 2032. The Reference Scenario assumes that the mandate is met by 2019 and remains at that percentage of retail load as load grows. The Environmental Focus Scenario also meets the 2019 mandate and grows to 15% by 2032.

- RENEWABLE ENERGY PLANNING ASSUMPTIONS

  In the 2013 IRP, the Company has assumed that a generic legislative requirement will be imposed at either the state or federal level, and that this requirement will drive the development of renewable resources over time. This assumption sets a minimum amount of renewable energy in each scenario. Each scenario begins with minimum renewables of 1% in 2018, rising to minimums of 4%, 5%, and 15% by 2032, in the Low Regulation, Reference, and Environmental Focus Scenarios, respectively. Assuming a continuing decline in the cost of wind and solar generation, those generation types become increasingly cost effective, particularly in scenarios that include a carbon emissions price.

- UNCERTAINTY IN A CARBON-CONSTRAINED FUTURE

  Duke Energy Indiana believes it is unlikely that legislation mandating reductions in Greenhouse Gas (GHG) emissions or establishing a carbon tax or carbon dioxide (CO_2) emission allowance price will be passed during the current session of Congress. Beyond 2014, the prospects for enactment of any federal legislation mandating reductions in GHG emissions or otherwise establishing a price on carbon emissions are highly uncertain. In the absence of federal GHG legislation, the EPA continues to pursue GHG regulations on new and existing electric generating units (EGUs). The EPA recently proposed carbon dioxide emission limits for new coal-fired electric generating units that would prohibit their construction without carbon capture and storage (CCS) technology. The EPA is currently targeting June 2014 to propose and June 2015 to finalize a rule to regulate CO_2 emissions from existing coal-fired EGUs. The impact of this future EPA regulation on existing coal-fired EGUs is uncertain. Despite this uncertainty, the Company believes that it is prudent to plan for the possibility of a carbon-constrained future. To address this possibility, the Company continues to evaluate portfolios under a range of carbon prices.

Duke Energy Indiana has considered a wide range of CO_2 cost assumptions in its group of scenarios. The Environmental Focus Scenario begins with $20/ton in 2020 and increases to $75/ton by 2033, with a related sensitivity growing to $100/ton by 2033. The Low Regulation Scenario features a $0/ton CO_2 cost in all years. The Reference Scenario begins with $17/ton in 2020, increasing to $50/ton by 2033.

We believe our current range of prices, including a zero price in the Low Regulation Scenario, is appropriate given the outcome of past debates over federal climate change legislation, the significant uncertainty surrounding the future direction of U.S. climate change policy, and our belief that to be potentially politically acceptable, climate change policy would need to be moderate. If or when there is clarity around future U.S. legislative or regulatory climate change policy, Duke Energy Indiana will adjust its assumptions related to carbon emissions as needed to reflect that clarity.

- CHANGES IN THE PROJECTED LOAD FORECAST

  Between 2011 and 2013, the total energy and peak capacity need for Duke Energy Indiana decreased across all customer classes primarily due to the impact of a weak economic recovery. While long-term trends point toward recovery, 2013 energy usage has still not returned to pre-2008 levels. Summer peak capacity needs have returned more quickly, with summer peak demand already ten percent above that of 2009.

The rest of this Executive Summary presents an overview of the resource plan. Further details regarding the planning process, issues, uncertainties, and alternative plans are presented in the chapters that follow. For further guidance on the location of information required the Commission's October 4, 2012 Proposed IRP Rules, see Appendix H.

B. PLANNING PROCESS RESULTS

To address uncertainties, the Company believes the most prudent approach is to create a plan that is robust under various future scenarios. Also, the Company must maintain flexibility to adjust to evolving regulatory, economic, environmental, and operating circumstances.

Scenario analysis was used as part of this year's IRP planning process. The macro level driving forces were discussed in our stakeholder meetings and those driving forces led to the development of three discrete and internally consistent scenarios.

1. Scenarios

The "**Low Regulation Scenario**" assumes:

- No tax/price on carbon
- Moderate levels of environmental legislation or regulation
- A low federal or state level renewable energy standard (4% in 2032)
- Slower implementation of EE at 7% in 2019, meeting the 11.9% state mandate in 2032
- Higher gas and coal prices due to the greater demand for fuels in this scenario

The "**Reference Scenario**" reflects the Company's view of the future and assumes:

- A carbon price of approx $17/ton in 2020 that grows to $50/ton in 2033
- Increased levels of environmental legislation or regulation
- A moderate federal or state level renewable energy standard (5% in 2032)
- Meeting the 11.9% state EE mandate in 2019 and sustaining that percentage thereafter
- Moderate gas and coal prices based on the demand for fuels in this scenario

The "**Environmental Focus Scenario**" assumes:

- A carbon price of approx $20/ton in 2020 that grows to $75/ton in 2033

- Stricter levels of environmental legislation or regulation
- A high federal or state level renewable energy standard (15% in 2032)
- Meeting the 11.9% state EE mandate in 2019 and increasing to 15% by 2032
- Lower gas and coal prices based on the lower demand for fuels in this scenario

Once the specific modeling assumptions for each scenario were determined, a capacity expansion model was used to optimize a portfolio for that scenario. The results of that modeling exercise are described in the Table 1-A.

2. <u>Portfolios</u>

Based on the assumptions for the Low Regulation Scenario, the **Traditional Portfolio** was developed. This portfolio features the retirement of a number of older coal- and oil-fired units. The conversion of Wabash River 6 to natural gas and the construction of several natural gas-fired combustion turbines (CTs) and combined cycle (CC) capacity replace the retired capacity and serve new load growth.

Based on the assumptions for the Reference Scenario, the **Blended Approach Portfolio** was developed. This portfolio features the retirement of the same units that were retired in the Traditional Portfolio. Wabash River 6 is converted to natural gas in the Blended Approach portfolio, and CTs, CCs, and partial ownership of a nuclear unit are added.

Based on the assumptions for the Environmental Focus Scenario, the **Coal Retires Portfolio** was developed. This portfolio assumes the retirement of all of the existing pulverized coal units. The Coal Retires portfolio includes CTs, CC's, a full nuclear unit, and a higher level of renewables and EE to replace the retired capacity and serve new load growth.

Table 1-A includes more detail for each portfolio. Figure 1-A shows how the capacity and energy in each portfolio changes over time.

Table 1-A: Portfolio Details

TRADITIONAL PORTFOLIO (Optimized for Low Regulation Scenario)

	2014-2018	2019-2023	2024-2028	2029-2033	Energy Efficiency (% of Retail Sales)	Renewable Energy (% of Total Sales)
Retirements	WR 2-6 Coal Connersville 1-2 CT MW 1-3, 5 & 6 CT	Gall 2,4 Coal		WR 6 NG Conversion	6% in 2020 12% in 2032	2% in 2020 4% in 2032
Additions	WR 6 NG Conversion New CT (400 MW)	New CT (600 MW)	New CT (400 MW)	New CC (680 MW)		

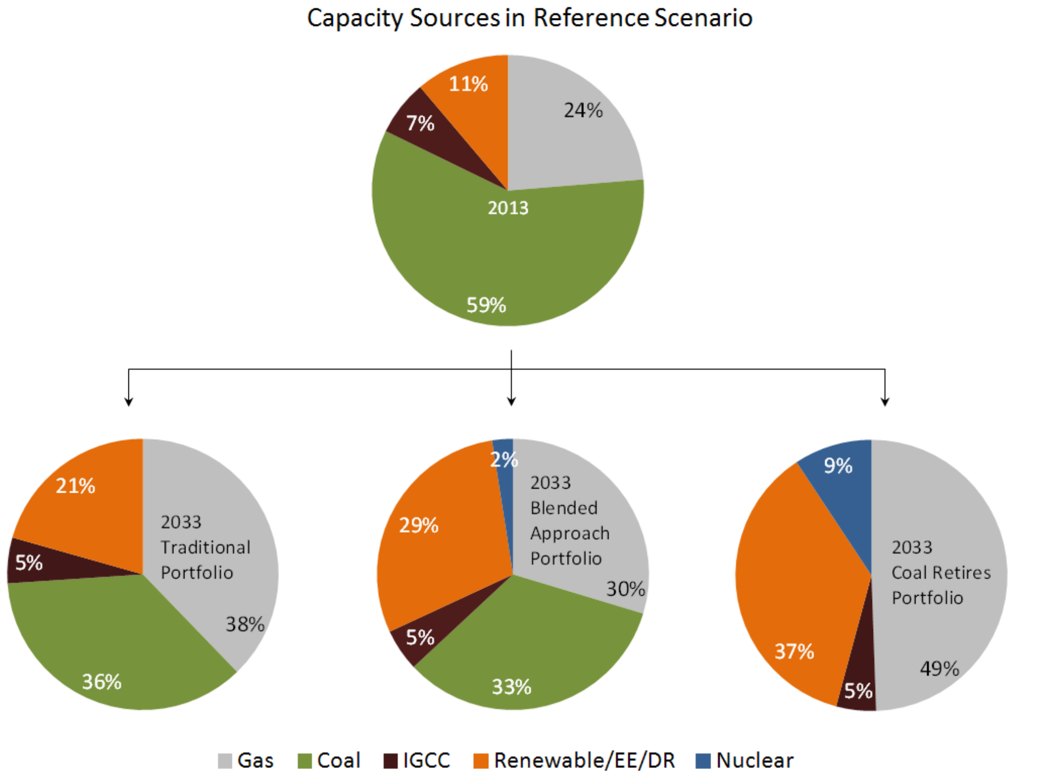
BLENDED APPROACH PORTFOLIO (Optimized for Reference Scenario)

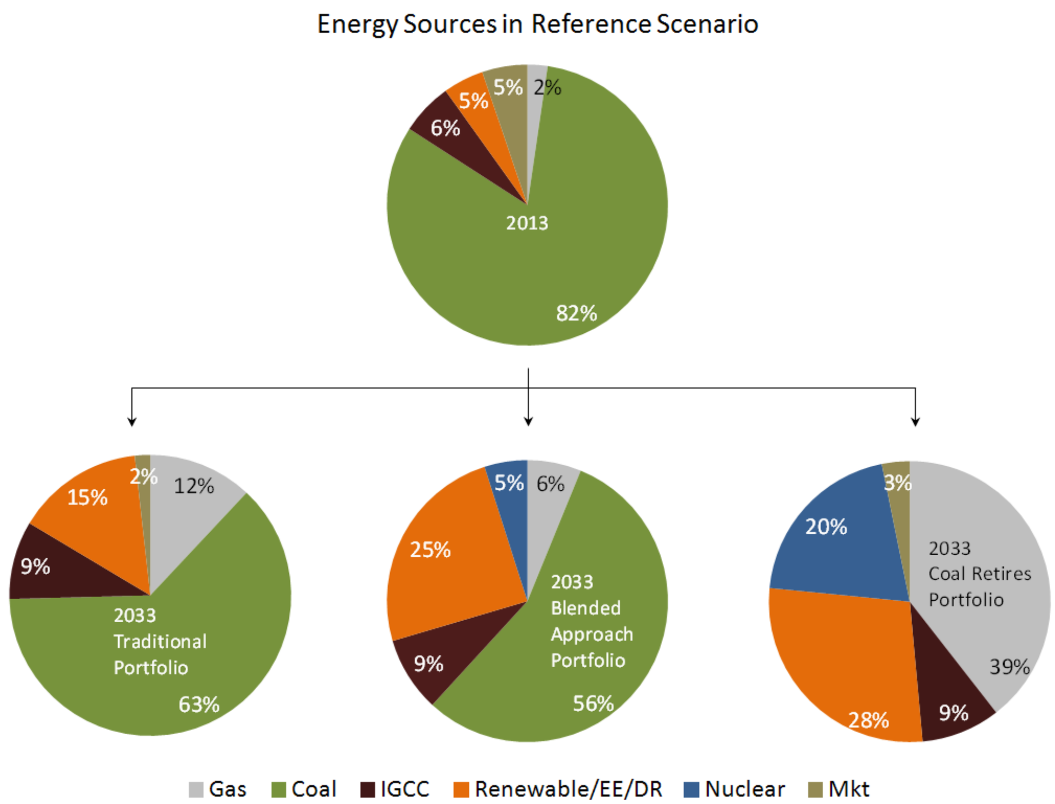
	2014-2018	2019-2023	2024-2028	2029-2033	Energy Efficiency (% of Retail Sales)	Renewable Energy (% of Total Sales)
Retirements	WR 2-6 Coal Connersville 1-2 CT MW 1-3, 5 & 6 CT	Gall 2,4 Coal		WR 6 NG Conversion	12% in 2020 12% in 2032	3% in 2020 14% in 2032
Additions	WR 6 NG Conversion	New CT (600 MW)	New CC (340 MW) New CT (200 MW)	New CC (340 MW) New Nuclear (280 MW)		

COAL RETIRES PORTFOLIO (Optimized for Environmental Focus Scenario)

	2014-2018	2019-2023	2024-2028	2029-2033	Energy Efficiency (% of Retail Sales)	Renewable Energy (% of Total Sales)
Retirements	WR 2-6 Coal Connersville 1-2 CT MW 1-3, 5 & 6 CT	Gall 2,4 Coal	Gibson 5 Coal	Cayuga 1,2 Coal Gibson 1-4 Coal	12% in 2020 15% in 2032	4% in 2020 15% in 2032
Additions	New CT (400 MW)	New CT (200 MW)	New CC (340 MW) New CT (600 MW)	New CC (2380 MW) New Nuclear (1120 MW) New CT (170 MW)		

Figure 1-A: Generation Mix 2013 and 2033





The objective of the IRP is to produce a robust portfolio that meets load obligation while minimizing the Present Value Revenue Requirements (PVRR), subject to laws and regulations, reliability and adequacy requirements, and operational feasibility. Also, the selected plan must meet MISO's 13.9% reserve margin requirement. Based on its superior performance in scenario and sensitivity analyses, the Blended Approach Portfolio was selected as the recommended resource plan.

Short Term:

Several small coal units (Wabash River 2-5) and oil-fired CT units (Connersville 1&2, Miami-Wabash 1-3 & 5-6) are expected to retire by 2018. The conversion of the Wabash River 6 unit to natural gas enables this unit to remain in service.

As new EPA regulations are finalized in 2013 and 2014, the Company will develop a detailed strategy and seek necessary regulatory approvals.

Long Term:

Longer term, Gallagher 2&4 could potentially retire in 2019; however, no decisions have been made at this time and we will continue to study this issue in future IRPs. The Wabash River 6 gas conversion is expected to operate for 15 years, then retire in 2031.

Future load obligations are met through a combination of renewable energy, new CT and CC, and a quarter share of a new nuclear unit. Approximately 900 MWs (nameplate) of renewable generation is added by 2027, with an additional 1450 MWs in the early 2030s due to the increasing price of CO_2.

An overview of the recommended resource plan is summarized in Table 1-B.

TABLE 1-B DUKE ENERGY INDIANA INTEGRATED RESOURCE PLAN BLENDED APPROACH PORTFOLIO AND RECOMMENDED PLAN (2013-2033)						
Year	Retirements	Additions	Renewables (Nameplate MW) [1]			Notable, Near-term Environmental Control Upgrades [2]
			Wind	Solar	Biomass	
2013						
2014						Gibson 4 Precipitator Refurb
2015	Wabash River 2-5 (350 MW)					Cayuga 1&2 SCRs Gibson 3 Precipitator Refurb Gibson 5 Precipitator Refurb
2016	Wabash River 6 Coal (318 MW)	Wabash River 6 NG Conversion (318 MW)				Gibson 5 FGD Refurb
2017						
2018	Connersville 1&2 CT (86 MW) Mi-Wabash 1-3,5-6 CT (80 MW)			60	4	
2019	Gallagher 2&4 (280 MW)	CT 200 MW	50	30		
2020		CT 200 MW	50	20	2	
2021			50	30		
2022			50	20	2	
2023		CT 200 MW		30		
2024			50	30	2	
2025		CT 200 MW	50	40	2	
2026			250	70		
2027		CC 340 MW			2	
2028						
2029						
2030		CC 340 MW				
2031	Wabash River 6 NG (318 MW)	Nuclear 280 MW	250			
2032			600			
2033			600			
Total MW	1432	2078	2000	330	14	

1: Wind and solar MW represent nameplate capacity.

2: Additional likely or potential control requirements include additives for mercury control, ash system modifications, landfill requirements, and intake structure modifications in the 2015 -2023 time frame.

2. SYSTEM OVERVIEW, OBJECTIVES AND PROCESS

A. INTRODUCTION

This chapter will explain the objectives of and the process used to develop the 2013 Duke Energy Indiana IRP. In the IRP process, the modeling includes the firm electric loads, supply-side and energy efficiency resources, and environmental compliance measures associated with the Duke Energy Indiana service territory. It also includes the Wabash Valley Power Association (WVPA) and Indiana Municipal Power Agency (IMPA) ownership shares in Gibson 5 and the corresponding load served by those shares through December 31, 2014, because Duke Energy Indiana provides reserve capacity and energy service from Gibson 5 until then.

B. CHARACTERISTICS OF GENERATING AND TRANSMISSION CAPABILITIES

The total installed net summer generation capability owned or purchased by Duke Energy Indiana is currently 7,503 MW.[1] This capacity consists of 4,765 MW of coal-fired steam capacity, 595 MW of syngas/natural gas combined cycle capacity, 285 MW of natural gas-fired combined cycle capacity, 45 MW of hydroelectric capacity, and 1,804 MW of natural gas-fired or oil-fired peaking capacity. Also included is a power purchase agreement with Benton County Wind Farm (100 MW, with 9 MW contribution to peak modeled).

The coal-fired steam capacity consists of 14 units at four stations (Gibson, Cayuga, Gallagher and Wabash River). The syngas/natural combined cycle capacity is comprised of two syngas/natural gas-fired combustion turbines and one steam turbine at the Edwardsport Integrated Gasification Combined Cycle (IGCC) station. The CC capacity consists of a single unit comprised of three natural gas-fired combustion turbines and two steam turbines at the Noblesville Station. The hydroelectric generation is a run-of-river facility comprised of three units at Markland on the Ohio River. The peaking capacity consists of seven oil-fired diesels at the Cayuga and Wabash River stations, seven oil-fired CT units at Connersville and Miami-Wabash, and 24 natural gas-fired CTs at five stations (Cayuga, Henry County, Madison,

[1] Excluding the ownership interests of IMPA (155 MW) and WVPA (155 MW) in Gibson Unit 5, and the ownership interest of WVPA (213 MW) in Vermillion, but including the non-jurisdictional portion of Henry County (50MW) associated with a long-term contract.

Vermillion, and Wheatland). One of these natural gas-fired units has oil back-up. Duke Energy Indiana also provides steam service to one industrial customer from Cayuga, which reduces Duke Energy Indiana's net capability to serve electric load by approximately 20 MW.

The Duke Energy Midwest bulk transmission system is comprised of the 345 kilovolt (kV) and 138 kV systems of Duke Energy Ohio and the 345 kV, 230 kV, and 138 kV systems of Duke Energy Indiana. The bulk transmission system delivers bulk power into, from, and across Duke Energy Midwest's service area. This bulk power is distributed to numerous substations that supply lower voltage sub-transmission systems, distribution circuits, or directly serve large customer loads. Because of the numerous interconnections with neighboring local balancing areas, the Duke Energy Midwest transmission system increases electric system reliability and decreases costs to customers by permitting the exchange of power and energy with other utilities on an emergency or economic basis.

As of December 2012, Duke Energy Indiana's wholly and jointly owned share of bulk transmission included approximately 721 circuit miles of 345 kV lines, 645 circuit miles of 230 kV lines and 1402 circuit miles of 138 kV lines. Duke Energy Indiana, IMPA, and WVPA have joint use of the Joint Transmission System (JTS) in Indiana. Duke Energy Indiana is directly interconnected with seven other local balancing authorities (American Electric Power, Louisville Gas and Electric Energy, Ameren, Hoosier Energy, Indianapolis Power and Light, Northern Indiana Public Service Company, and Vectren), plus Duke Energy Ohio.

Duke Energy Indiana is a member of the Midcontinent Independent System Operator, Inc. (MISO) and is subject to the overview and coordination mechanisms of MISO. All of Duke Energy Indiana's transmission facilities, including those transmission facilities owned by WVPA and IMPA but operated and maintained by Duke Energy Indiana, are encompassed in these MISO planning processes.

C. <u>OBJECTIVES</u>

An IRP process generally encompasses an assessment of a variety of supply-side, energy efficiency, and environmental compliance alternatives leading to the formation of a diversified, long-term, cost-effective portfolio of options intended to satisfy the electricity demands of customers located within a service territory. The purpose of this IRP is to outline a strategy to furnish these electric energy services over a 20-year planning horizon.

The planning process itself must be dynamic and adaptable to changing conditions. This resource plan represents one possible outcome based upon a single snapshot in time along this continuum. While it is the most appropriate resource plan at this point in time, good business practice requires Duke Energy Indiana to continue to study the options and make adjustments as necessary to reflect improved information and changing circumstances. Consequently, a robust analysis is an evolving process that can never be considered complete. In an effort to be better prepared for these circumstances, the Company performed scenario and sensitivity analyses that measure the impact of CO_2 cost, customer load, renewable energy requirements, capital cost, and fuel prices under three future scenarios.

The major objectives of the plan presented in this filing are to:

- Provide adequate, reliable, and economic service to customers while meeting all environmental requirements
- Maintain the flexibility and ability to alter the plan in the future as circumstances change
- Choose a near-term plan that is robust over a wide variety of possible futures
- Minimize risks (such as wholesale market risks, reliability risks, *etc*.)

D. ASSUMPTIONS

The analysis performed to prepare this IRP covers the period 2013-2033. The base planning assumptions in the 2013 resource plan include:

- EE – On December 9, 2009, the Commission issued its Phase II Order in Cause No. 42693 (Phase II Order). In the Phase II Order, the Commission found that jurisdictional electric utilities are required to offer certain Core Energy Efficiency Programs to all customer classes and market segments. To implement these programs, the Commission determined that an independent Third Party Administrator (TPA) should be utilized by the electric utilities to oversee the administration and implementation of the Core Programs. The Commission also established annual gross energy savings targets for all jurisdictional electric utilities and directed utilities to offer Core Plus programs in addition to the Core Program offering. Duke Energy Indiana intends to continue to be a leader in EE by offering programs through a combination of Core Programs to be offered by a TPA and Core Plus Programs offered by Duke Energy Indiana. The Core Plus programs have been approved under Cause 43955 and Duke Energy Indiana is currently implementing this portfolio of EE measures.

- Renewable Energy – There is not currently an Indiana or federal renewable energy portfolio standard (REPS). However, to assess the impact to the long-term resource need, the Company believes it is prudent to plan for a renewable energy portfolio standard. Each scenario begins with minimum renewables of 1% in 2018, rising to minimums of 4%, 5%, and 15% by 2032, in the Low Regulation, Reference, and Environmental Focus Scenarios, respectively.
- Carbon-Constrained Future – Although there is continued legislative and regulatory uncertainty surrounding future carbon emissions requirements, the ongoing interest in such restrictions requires the IRP to include costs for potential carbon taxes, allowances, and/or limits. The Environmental Focus Scenario begins with $20/ton in 2020 and increases to $75/ton by 2033, with a related sensitivity growing to $100/ton by 2033. The Low Regulation Scenario features a $0/ton CO_2 cost in all years. The Reference Scenario begins with $17/ton in 2020, increasing to $50/ton by 2033.
- New Environmental Regulatory Requirements – The estimated capital and operation and maintenance impacts of multiple new and proposed environmental regulations were included. The most impactful of these regulations include:
  - The final EPA MATS Rule - Creates emission limits for hazardous air pollutants (including mercury, non-mercury metals, and acid gases) starting in 2015. Control upgrades vary by station ranging from fuel and process chemical additives to new SCR installations.
  - Final 1-hour 75ppb SO_2 National Ambient Air Quality Standard (NAAQS) – Potential to further limit the amount of SO_2 that can be emitted from a facility. Currently, only the Wabash River station is in a region that has been identified as non-attainment, requiring near-term action. Additional SO_2 controls (mainly process chemical additives to existing SO_2 scrubbers) on other coal-fired units are expected in the 2020 timeframe.
  - Future reductions in the Ozone NAAQS – Potential for additional NO_x reductions on facilities is expected in the 2020 timeframe to meet a new lower ozone standard.

- Coal Combustion Residuals (CCR) Rule and Steam Electric Effluent Limitations Guidelines (ELG) Revisions – Anticipated requirements include converting to dry flyash and bottom ash removal, upgrading waste water treatment systems, and waste disposal in a lined landfill versus a wet ash basin.
- Fish Impingement and Entrainment Standards (316(b) rule) – Intended to reduce the amount of fish impinged on the intake screen or entrained through the condenser cooling water system. Expected compliance requirements range from barrier nets to intake structure modifications with fine mesh screen installations.

Risks associated with changes to the assumptions are addressed through scenario and sensitivity analyses and qualitative reasoning in Chapters 5, 6, and 8. This IRP uses a flat 2.5% escalation rate for the period of study. Duke Energy Indiana's financial departments provided the after-tax effective discount rate of 6.53%.

1. Reliability Criteria

Reliability*First* Resource Adequacy

Duke Energy Indiana's reserve requirements are impacted by Reliability*First*, which has adopted a Resource Planning Reserve Requirement Standard that the Loss of Load Expectation (LOLE) due to resource inadequacy cannot exceed one day in ten years (0.1 day per year). This Standard is applicable to the Planning Coordinator, which is MISO for Duke Energy Indiana.

MISO Module E-1 Resource Requirements

The MISO Tariff includes a long-term resource adequacy requirement similar to the Reliability*First* requirement. Beginning with Planning Year June 1, 2009 – May 31, 2010, the LOLE standard became enforceable under MISO's tariff and there are financial consequences for violating it.[2]

[2] The deficiency charges are based on the Cost of New Entry (CONE). The 2013/14 CONE value for Zone 6 (which includes Indiana) is $99,860 per MW-year.

The Planning Reserve Margin (PRM) that is assigned to each load serving entity (LSE) is on a UCAP (*i.e.*, unforced capacity) basis. The PRM on an ICAP (*i.e.*, installed capacity) basis is translated to PRM_{UCAP} using the MISO system average equivalent forced outage rate excluding events outside of management control ($XEFOR_d$).[3] Each capacity resource is valued at its UCAP rating (*i.e.*, ICAP rating multiplied by 1 minus the unit-specific $XEFOR_d$).

Beginning with Planning Year 2013/14, MISO moved to an annual capacity construct that also includes locational capacity requirements. Each LSE is required to have Zonal Resource Credits (ZRCs)[4] equivalent to 1 plus the PRM_{UCAP} multiplied by the LSE's annual forecasted peak load coincident with MISO's peak. For the 2013/14 Planning Year, Duke Energy Indiana is required to meet a PRM_{UCAP} of 6.2%. However, for IRP purposes, it is necessary to translate PRM_{UCAP} to an equivalent Installed Capacity Reserve Margin (RM_{ICAP}) target (*i.e.*, the historical method used by Duke Energy Indiana) so that the modeling can be performed correctly. For Planning Year 2013/14, the applicable RM_{ICAP} is 14.4%.[5]

For longer-term planning, the RM_{ICAP} should be adjusted for known changes in the future such as the retirement of Wabash River 2-5 (due to MATS compliance) and the expiration of the Gibson 5 Reserve Capacity contracts. Therefore, the minimum Reserve Margin criterion utilized in this IRP analysis as being indicative of the required level of reserves going forward is 13.9%, based on the Planning Year 2013/14 PRM_{UCAP} along with Duke Energy Indiana's coincidence with the MISO peak. To the extent that the actual PRM_{UCAP} for future Planning Years differs from that for Planning Year 2013/14, Duke Energy Indiana may require either a higher or lower level of reserves than what is shown in this IRP.[6]

[3] $PRM_{UCAP} = (1 - \text{MISO Average } XEFOR_d)(1 + PRM_{ICAP}) - 1$

[4] 1 ZRC is equal to 1 MW of UCAP capacity for generators or Behind The Meter Generation (BTMG) in a particular Zone.

[5] $RM_{ICAP} = \text{Coincidence Factor X } [(PRM_{UCAP} + 1) / (1 - \text{Duke Energy Indiana Average } XEFOR_d)] - 1$

[6] MISO's preliminary PRM_{UCAP} for PY 2014/15 has increased to 7.3%. All else unchanged, this would result in an applicable RM_{ICAP} for Duke Energy Indiana of 15.1%. Duke Energy Indiana will calculate the applicable RM_{ICAP} in the coming months once MISO's PRM_{UCAP} is final, taking into account the most recent unit capability tests, $XEFOR_d$ values, and the Company's coincidence with the MISO peak.

E. PLANNING PROCESS

Every two years, Duke Energy Indiana prepares an IRP pursuant to the definition given in the Indiana Administrative Code Rule 7, Guideline for Integrated Resource Planning by an Electric Utility. In response to the proposed rule amending Rule 7, the addition of a stakeholder process has been added to our planning process. Therefore, the process used to develop the IRP for this year consisted of three major components: an organizational process, an analytical process, and the addition of the new stakeholder process.

1. Organizational Process

Development of an IRP requires a high level of communication across key functional areas. Duke Energy Indiana's IRP Team, which manages this process, consists of experts in the following key functional areas: electric load forecasting, resource (supply) planning, retail marketing (energy efficiency program development and evaluation), environmental compliance planning, environmental policy, financial, fuel planning and procurement, engineering and construction, and transmission and distribution planning. It is the Team's responsibility to examine the IRP requirements contained within the Indiana rules and conduct the necessary analyses to comply with the filing requirements.

A key step in the preparation of the IRP is the integration of the electric load forecast, supply-side options, environmental compliance options, and energy efficiency options. In addition, it is important to conduct the integration while also incorporating interrelationships with other areas.

2. Analytical Process

The development of an IRP is a multi-step process involving the key functional planning areas mentioned above. The steps involved are listed below. To facilitate timely completion of this project, a number of these steps are performed in parallel.

1. Develop planning objectives and assumptions.
2. Prepare the electric load forecast (Chapter 3).
3. Identify and screen potential cost-effective EE resource options (Chapter 4).
4. Identify and screen potential cost-effective supply-side resource options (Chapter 5).

5. Identify and screen potential cost-effective environmental compliance options (Chapter 6).
6. Integrate the EE, supply-side and environmental compliance options (Chapter 8).
7. Perform final scenario and sensitivity analyses on the integrated resource alternatives and recommend a plan (Chapter 8).
8. Determine the best way to implement the recommended plan (Chapter 8, Appendix D).

3. Stakeholder Process

In response to the proposed rule, Duke Energy Indiana has conducted five stakeholder meetings to discuss the IRP process with stakeholders as well as gather stakeholder input. The five stakeholder meetings are summarized below:

Stakeholder Meeting #1 - December 5, 2012

- Background on stakeholder process
- Discussion of driving forces in order to develop scenarios

Stakeholder Meeting #2 - January 30, 2013

- Discussion of EE & Renewable Energy
- Stakeholder exercise to develop scenarios

Stakeholder Meeting #3 - April 24, 2013

- Discussion of Load Forecasting and Market Fundamentals
- Discussion of modeling assumptions

Stakeholder Meeting #4 - July 19, 2013

- Stakeholder Feedback and Response discussion
- Scenario Review, Modeling Methodology & Portfolios Discussion

Stakeholder Meeting #5 - October 9, 2013

- Scenario & Portfolios Review
- Decision and Risk Management discussion
- Presentation of preferred portfolio and short term implementation plan

Materials covered and meeting summaries are included in Volume 2 and are posted on the company's website at: http://www.duke-energy.com/indiana/in-irp.asp

3. ELECTRIC LOAD FORECAST

A. GENERAL

The electric energy and peak demand forecasts of the Duke Energy Indiana service territory are prepared each year by a staff shared with the other Duke Energy Indiana affiliated utilities. Although the Duke Energy Indiana load forecast is developed independently of the projections for other Duke Energy Indiana affiliate-served territories, the overall methodology is the same.

B. FORECAST METHODOLOGY

Energy is a key cornerstone of economic activity. As residential, commercial, and industrial economic activity increases or decreases, the use of energy, or more specifically electricity, should increase or decrease, respectively. It is this linkage to economic activity that is important to the development of long-range energy forecasts. For that reason, forecasts of the national and local economies must be key ingredients to energy forecasts.

The general framework of the electric energy and peak demand forecast of the Duke Energy Indiana System involves a national economic forecast, a service area economic forecast, and the electric load forecast.

The national economic forecast provides information about the growth of the national economy. This involves projections of national economic and demographic concepts such as population, employment, industrial production, inflation, wage rates, and income. The national economic forecast is obtained from Moody's Analytics, a national economic consulting firm.

Similarly, the history and forecast of key economic and demographic concepts for the Duke Energy Indiana service area economy is also obtained from Moody's Analytics. The service area economic forecast is used along with the energy and peak models to produce the electric load forecast.

1. Service Area Economy

Duke Energy Indiana provides electric service to customers in portions of 69 counties in North Central, Central and Southern Indiana. Currently, on a retail sales basis, Duke Energy

Indiana provides electric service to 5 percent or more of the population in 61 of these counties. Duke Energy Indiana’s service area includes numerous municipal utilities and Rural Electric Membership Cooperatives, some of which are Duke Energy Indiana’s wholesale customers.

There are four major dimensions to measuring the service area economy: employment, income, inflation, and population. Forecasts of employment are provided according to North American Industry Classification System (NAICS) code and aggregated to major sectors such as commercial and industrial. Income for the local economy is forecasted in several categories including wages, rents, proprietors’ income, personal contributions for social insurance, and transfer payments. The forecasts of these items are summed to produce the forecast of income less transfer payments (such as personal contributions for social insurance). Inflation is measured by changes in the Consumer Price Index (CPI). Population projections are aggregated from forecasts by age-cohort. Taken all together, this information serves as input into the energy and peak load forecast models.

2. <u>Electric Energy Forecast</u>

The following sections provide the specifications of the econometric equations developed to forecast electricity sales for Duke Energy Indiana.

Several sectors comprise the Duke Energy Indiana Electric Load Forecast Model. Forecasts are prepared for electricity sales to the residential, commercial, industrial, governmental, other, and wholesale energy sectors. Additionally, projections are made for summer and winter peak demands.

Residential Sector - There are two components to Duke Energy Indiana's residential sector energy forecast: the number of residential customers and energy use per customer. The forecast of total residential sales is developed by separately estimating and then multiplying the forecasts of these two components.

Customers - The number of electric residential customers (households) is affected by population and real per capita income. Because the number of customers will change gradually over time in response to changes in population and real per capita income, this adjustment process is modeled using lag structures.

Residential Use per Customer - The key drivers of energy use per customer are real (*i.e.*, in inflation-adjusted terms) per capita income, real electricity prices and the combined impact of numerous other determinants. These include the saturation of air conditioners, electric space heating, other appliances, the efficiency of those appliances, and weather.

Commercial Sector - Commercial electricity usage changes with the level of local commercial employment, real electricity price, and the impact of weather.

Industrial Sector - Duke Energy Indiana produces industrial sales forecasts based on projections of regional manufacturing GDP. Electricity use by industrial customers is primarily dependent upon the level of industrial production and the impacts of real electricity prices, electric price relative to alternate fuels, and weather.

Governmental Sector – The Company uses the term Other Public Authorities (OPA) to indicate those customers involved and/or affiliated with federal, state or local government. Electricity usage for this sector is related to governmental employment, the real price of electricity, and heating and cooling degree days.

Other - Duke Energy Indiana provides electricity for municipal activities such as street and highway lighting and traffic signals. This “other” sales category is forecasted using projected trends from the Energy Information Administration.

Total Retail Electricity Sales - Once these separate components have been projected - Residential sales, Commercial sales, Industrial sales, OPA sales, and Other sales - they can be summed to produce the projection of total retail electricity sales.

Wholesale - Duke Energy Indiana provides electricity on a contract basis to various wholesale customers. Loads for these wholesale customers are forecasted using specifications contained within the active contracts and historical trend analysis.

Total System Sendout/Net Energy For Load - Upon completion of the total electric sales forecast, the total Duke Energy Indiana system sendout or net energy for load forecast can be prepared. This requires that all the individual sector forecasts be combined along with forecasts of Wholesale sales and system losses. After the system sendout forecast is completed, the peak load forecast can be prepared.

Weather-Normalized Sendout - The level of peak demand is related to economic conditions such as income and prices. The best indicator of the combined influences of economic variables on peak demand is the level of base load demand exclusive of aberrations caused by non-normal weather. Thus, the first step in developing the peak equations described above is to weather-normalize monthly sendout.

The procedure used to develop historical weather-normalized sendout data involves two parts. First, instead of weather-normalizing sendout in the aggregate, each sales component is weather-normalized (adjusted for the difference between normal and actual weather) individually. With this process, weather-normalized sales are computed by scaling actual sales for each class by a factor from the forecast equation that accounts for the impact of deviations from normal monthly weather. Industrial sales are weather-normalized using a factor from an aggregate equation developed for that purpose. Wholesale loads are weather-normalized using the factors developed from the retail sector depending on contract terms and/or service type.

Second, weather-normalized sendout is computed by summing the weather-normalized sales with non-weather sensitive sector sales and other miscellaneous components. This weather-adjusted sendout is then used as a variable in the summer and winter peak equations.

Peak Load - Forecasts of summer and winter peak demands for Duke Energy Indiana are developed using econometric models.

The peak forecasting model is designed to represent closely the relationship of weather to peak loads. Only days when the temperature equaled or exceeded 90 degrees are included in the summer peak model. For the winter, it is a standard procedure that only those days with a temperature at or below a predetermined threshold are included in the winter peak model.

Summer Peak - Summer peak loads are influenced by the current level of economic activity and the weather conditions. The primary weather factors are temperature and humidity; however, not only are the temperature and humidity around the time of the peak important, but also the morning low temperature, and the high temperature from the day before. These other temperature variables are important to capture the effect of thermal buildup.

Winter Peak - Winter peak loads are also influenced by the current level of economic activity and the weather conditions. The selection of winter weather factors depends upon whether the peak occurs in the morning or evening. For a morning peak, the primary weather factors are morning low temperatures, wind speed, and the prior evening's low temperature. For an evening peak, the primary weather factors are the evening low temperature, wind speed, and the morning low temperature.

The summer and winter peak equations are estimated separately for the respective seasonal periods. Peak load forecasts are produced under specific assumptions regarding the type of weather conditions typically expected to cause a peak.

Peak Forecast Procedure - The summer peak usually occurs in August in the afternoon and the winter peak most often occurs in January in the morning. (July and February—respectively—are also possible). Since the energy model produces forecasts under the assumption of normal weather, the forecast of sendout is "weather-normalized" by design. Thus, the forecast of sendout drives the forecast of the peaks. In the forecast, the weather variables are set to values determined to be normal peak-producing conditions. These values are derived using historical data on the weather conditions in each year (summer and winter).

C. ASSUMPTIONS

1. Macro Assumptions

It is generally assumed that the Duke Energy Indiana service area economy will tend to behave much like the national economy. Duke Energy Indiana uses a long-term forecast of the national and service area economy prepared by Moody’s Analytics.

2. Local Assumptions

The Duke Energy Indiana service area has traditionally been strongly influenced by the level of manufacturing activity. While manufacturing employment declines over the forecast period, increasing manufacturing productivity and a general economic rebound will keep both total manufacturing output and industrial energy sales increasing, although at a slower rate than what was expected in 2011. The majority of the employment growth over the forecast period occurs in the non-manufacturing sector. This reflects a continuation of the trend toward the service industries and the fundamental changes that are occurring in manufacturing and other basic industries.

Duke Energy Indiana is also affected by national population trends. The average age of the U.S. population is rising. The primary reasons for this phenomenon are stagnant birth rates and lengthening life expectancies. As a result, the portion of the population of the Duke Energy Indiana service area that is “age 65 and older” increases over the forecast period. Over the period 2013 to 2023, Duke Energy Indiana's population is expected to increase at an annual average rate of 0.6 percent. Nationally, population is expected to grow at an annual rate of 0.9 percent over the same period, with much of the difference accounted for by differences in migration. The Duke Energy Indiana service area has a more favorable inflow of residents than Indiana as a whole: among the four counties that lost 1,000 or more residents to outmigration from 2010-2012, only Elkhart County is in the Duke Energy Indiana service territory.

The residential sector is the largest in terms of total existing customers and total new customers per year. Within the Duke Energy Indiana service area, many commercial customers serve local markets. Therefore, there is a close relationship between the growth in local residential customers and the growth in commercial customers. The number of new industrial customers added per year is relatively small.

3. Customer Self-Generation

For many years, many industrial customers, and some commercial customers, have inquired about cogeneration, the sequential production of electricity and process heat or steam. There have only been a few cases in which cogeneration has been installed, due in part to the difficulty of making these projects economical. No additional cogeneration units that impact the load forecast are assumed to be built or operated within the Duke Energy Indiana service area during the forecast period; however, the renewables or EE categories in this IRP can be considered placeholders for any new projects.

In the area of other self-generation, several units are in place within Duke Energy Indiana's service territory to provide a source of emergency backup electricity. Where economical, a number of these units participate and are represented under Duke Energy Indiana's CallOption or QuoteOption program under PowerShare®.

D. DATABASE DOCUMENTATION

1. Economic Data

The major series of data in the economic forecast are employment, income, demographics, national production, and national employment. The source of this information is Moody's Analytics. In general, state level data are used, as many of the local areas in Duke Energy Indiana's service territory buy and sell from nearby areas. These economic connections are sufficiently strong to support this methodology.

Employment - State-wide employment statistics are used by industry for both the manufacturing and non-manufacturing categories.

Income - Updates of historical local income data series are gathered at the state level. This is performed for total personal income, which includes dividends, interest and rent; wage and salary disbursements plus other labor income; non-farm proprietors' income; transfer payments; and personal contributions for social insurance.

Population - Population statistics are gathered at the state level.

Manufacturing_Activity – Manufacturing GDP and employment statistics are obtained for the Indiana region. This information is utilized in the forecast of industrial sales.

2. Energy and Peak Data

The majority of data required to develop the electricity sales and peak forecasts is obtained from the Duke Energy Indiana service area economic data provided by Moody's Analytics, from Duke Energy Indiana financial reports and research groups, and from national sources. With regard to the national sources of information, generally all national information is obtained from Moody's Analytics. However, local weather data are obtained from the National Oceanic and Atmospheric Administration (NOAA).

The major groups of data that are used in developing the energy forecasts are: kilowatt-hour sales by customer class, number of customers, use-per-customer, electricity prices, natural gas prices, appliance saturations, and local weather data.

Kilowatt-hour Sales and Revenue - Duke Energy Indiana collects sales and revenue data monthly by rate class. For forecast purposes this information is aggregated into the following categories: residential, commercial, industrial, OPA, and the other sales category. In the industrial sector, sales data for each manufacturing NAICS category are collected. Statistics regarding sales and revenue for each wholesale customer are also collected. From the sales and revenue information, average electricity prices by sector can be calculated.

Number of Customers - The number of customers by sector, on a monthly basis, is also obtained from Duke Energy Indiana records. From the sales and customer data, average electricity use per customer can be calculated.

Natural Gas Prices - Natural gas prices are provided by Moody's Analytics.

Saturation of Appliances - The saturation of appliances within the service area is provided via customer surveys conducted by the Company's Market Research group and by the Energy Information Administration.

Local Weather Data

Local climatologic data are provided by NOAA for the Indianapolis reporting station.

Peak Weather Data

The weather conditions associated with the monthly peak load are collected from the hourly and daily data recorded by NOAA. The weather variables which influence the summer peak are maximum temperature on the peak day and the day before, morning low temperature, and humidity on the peak day. The weather influence on the winter peak is measured by the low temperatures and the associated wind speed. The variables selected are dependent upon whether it is a morning or an evening peak load.

An average of extreme weather conditions is used as the basis for the weather component in the preparation of the peak load forecast as previously discussed. Using historical data for the single weather occurrence on the summer peak day and the single weather occurrence on the winter peak day in each year, an average extreme weather condition can be computed for each season.

3. Forecast Data

Projections of exogenous variables in Duke Energy Indiana's models are required in the following areas: national and local employment, income, industrial production, and population, as well as natural gas and electricity prices. The projections for employment, income, industrial production and population are obtained from Moody's Analytics.

Population – The sales forecast uses the Moody's Analytics population projections for the state of Indiana.

Natural Gas Prices – The forecast of natural gas prices is provided by the corporate fundamental forecast team.

Electricity Prices - The projected change in electricity prices over the forecast interval is derived from company records and from the Energy Information Administration.

E. MODELS

Specific analytical techniques have been employed for development of the forecast models. Regression analysis (sometimes referred to as "Ordinary least-squares") is used to estimate behavioral relationships among relevant variables. Based upon their relationship with the electric sales, several independent variables are tested in the regression models, with the final models chosen based upon their statistical strength and logical consistency. We employ necessary corrections—such as the Marquardt algorithm—for the time-series structure of the data, which can lead to problems with nearby observations being correlated with each other.

When relationships are not necessarily linear, other transformations of the data can be used to improve the model. Therefore, in order to identify the true and consistent underlying economic relationship between the dependent variable and the other independent variables, qualitative variables are employed to account for the impact of these outliers. Finally, additional qualitative variables can be employed to exclude particular observations that are distorted by severe restrictions, labor-management disputes, or data reporting errors, from affecting the economic relationship that we report herein.

F. FORECASTED DEMAND AND ENERGY

On the following figures, the loads for Duke Energy Indiana are provided.

1. Service Area Energy Forecasts

Figure 3-B contains the energy forecast for Duke Energy Indiana's service area.

Residential use for the twenty-year period of the forecast for the entire Duke Energy Indiana service area is expected to increase an average of 1.5% per year; Commercial use, 1.6% per year; Industrial use, 0.5% per year; and Sales for Resale, -1.3% per year. The summation of the forecasts across all sectors and including losses results in an annual forecast growth rate of 0.6% for Net Energy for Load.

2. System Seasonal Peak Load Forecast

Figure 3-C contains forecasts of the summer and succeeding winter peaks for the Duke Energy Indiana service area. Historically, the summer peak exceeds the succeeding winter peak. Projected 20-year growth in peak demand is 0.9% summer and -0.2% winter.

3. Controllable and Interruptible Loads

There are controllable loads included in the forecast. Due to the nature of the operation of customers, it is possible that load may be reduced. The amount of load reduction depends upon the level of operation of the particular customers. See Chapter 4 for a complete discussion of the impacts of interruptible and other demand response programs. The difference between the internal and native peak loads consists of the impact from the interruptible and other demand response programs.

4. Load Factor

Figure 3-A below shows the annual load factor for Duke Energy Indiana. It shows the relationship between Net Energy for Load, Figure 3-B and the annual peak, Figure 3-C.

Figure 3-A

Year	Load Factor
2013	63.3%
2014	62.9%
2015	61.6%
2016	61.5%
2017	61.4%
2018	61.0%
2019	60.9%
2020	60.5%
2021	60.3%
2022	60.2%
2023	60.0%
2024	59.9%
2025	59.8%
2026	59.7%
2027	59.5%
2028	59.4%
2029	59.2%
2030	58.9%
2031	59.0%
2032	58.9%
2033	58.7%

5. Range of Forecasts

For the first five years of the forecast horizon, the high and low scenarios were prepared by estimating what the energy and peak load demands would be under a favorable and an unfavorable economic environment. Starting on year six and beyond, the high and low forecasts were developed by applying the standard error of the regression models and using a

95% confidence interval. Figures 3-D, 3-E, and 3-F show the results of the scenario analysis. The compound annual growth rate over the 20 year planning period is 0.95% for the most likely case.

6. Indiana Utilities Standardized Load Forecast Template

A standardized load forecast template, which was agreed upon by the Indiana utilities involved in the IRP Investigation Cause No. 43643, is shown in the Appendix F, Table F-2.

7. Comparison of Forecast to Past Forecasts

There are several noteworthy changes in the information available to Duke Energy Indiana concerning future economic conditions, with this new information causing small changes to our forecasts for both energy and for peak load. The long-term forecast for Net Energy for Load (Table 3-B) has decreased slightly (4% less in 2031) relative to the 2011 forecast; this is best attributed to substantial downward revisions in forecast demand from Industrial and OPA customers.

The growth of manufacturing GDP during early 2013 is less than what was forecast during the preparation of the previous forecast. The economy has felt a lot of pressure from the resumption of the payroll tax on most households. Industrial customers specifically appear to be "doing more with less," as their increased sales have not translated into increased demand for energy or manufacturing jobs at nearly the same rate. Facing increased fiscal pressure, OPA customers are shedding budgets and jobs. In the short term, they have decreased energy consumption, delaying our forecast load increases from what was previously expected. OPA customers are expected to be using 15% less energy in 2031 than was presented in the 2011 forecast.

Many economic indicators increased throughout 2012 and are now at significantly higher levels than at any time since the start of the financial crisis and recession. The University of Michigan Consumer Confidence continued rising throughout the summer; it is now higher than any value since 2007. Reports from the National Federation of Independent Business and the beige book have business owners less optimistic, however. The dip at the beginning of 2013 caused by the increase in the payroll tax has caused a noticeable softening in consumer demand, and employment throughout Indiana is still more than 100,000 jobs below where it was ten years ago. The recovery has been and continues to be weaker than many expected.

A slight increase in commercial demand is expected during 2013-2016. Expectations for wholesale demand decrease going forward. Along with decreases in total energy, forecasts for future peak load have also decreased. Much of this is attributed to expectations of rapid increases in offsetting energy efficiency measures, particularly for years 2013-2015.

Figure 3-B
Duke Energy Indiana
Service Area Energy Forecast (Magawatt Hours) (a)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) = sum (1) thru (7)	(9)	(10) = (8) + (9)
		Rural and Residential	**Commercial**	**Industrial**	**Street Lighting**	**Governmental**	**Resale (b)**	**Customer Use**	**Total Consumption**	**Losses and Unaccounted for (c)**	**Net Energy for Load**
-5	2008	9,267,376	6,263,112	10,791,662	54,225	2,280,867	7,700,805	42,474	36,400,521	1,950,952	38,351,473
-4	2009	8,901,481	6,008,141	9,031,515	54,196	2,258,574	7,675,465	38,098	33,967,470	1,894,728	35,862,198
-3	2010	9,609,251	6,228,528	10,081,641	53,878	2,256,283	7,630,580	37,959	35,898,121	1,913,888	37,812,009
-2	2011	9,316,050	6,155,986	10,236,733	53,601	2,203,288	5,370,379	35,142	33,371,179	1,181,158	34,552,337
-1	2012	8,867,465	6,152,090	10,411,454	53,182	2,162,219	5,796,106	32,338	33,474,853	601,535	34,076,388
0	2013	8,808,442	6,014,695	10,506,226	52,923	2,149,895	6,470,763	30,639	34,033,581	2,071,805	36,105,386
1	2014	8,823,834	6,112,612	10,647,711	52,665	2,191,313	6,477,741	30,639	34,336,516	2,095,126	36,431,641
2	2015	8,878,511	6,225,364	10,816,114	52,409	2,211,624	4,299,487	30,639	32,514,147	2,119,435	34,633,582
3	2016	8,970,047	6,288,311	10,892,262	52,153	2,205,805	4,624,444	30,639	33,063,661	2,141,536	35,205,197
4	2017	9,066,037	6,280,181	10,897,322	51,636	2,181,671	4,746,325	30,639	33,253,811	2,146,602	35,400,413
5	2018	9,130,433	6,256,364	10,807,099	50,704	2,145,772	4,744,964	30,639	33,165,973	2,142,136	35,308,109
6	2019	9,161,518	6,217,758	10,690,772	49,777	2,105,158	4,743,908	30,639	32,999,528	2,132,673	35,132,201
7	2020	9,243,764	6,253,363	10,682,632	48,854	2,085,058	4,758,914	30,639	33,103,223	2,139,793	35,243,015
8	2021	9,408,749	6,364,911	10,786,592	47,936	2,086,945	4,708,176	30,639	33,433,947	2,166,270	35,600,217
9	2022	9,553,908	6,486,124	10,887,798	47,024	2,089,536	4,715,648	30,639	33,810,675	2,193,337	36,004,012
10	2023	9,706,498	6,606,954	10,987,040	46,116	2,092,625	4,723,220	30,639	34,193,092	2,220,840	36,413,932
11	2024	9,862,338	6,727,144	11,081,274	45,213	2,095,284	4,742,307	30,639	34,584,199	2,248,370	36,832,568
12	2025	10,021,231	6,849,665	11,175,295	44,314	2,098,504	4,738,365	30,639	34,958,014	2,275,913	37,233,927
13	2026	10,178,849	6,974,589	11,261,328	43,421	2,100,328	4,745,694	30,639	35,334,848	2,303,078	37,637,926
14	2027	10,338,975	7,102,327	11,311,954	42,532	2,100,751	4,752,963	30,639	35,680,143	2,328,069	38,008,211
15	2028	10,502,686	7,234,789	11,372,613	41,648	2,101,577	4,771,820	30,639	36,055,772	2,354,608	38,410,380
16	2029	10,671,481	7,370,844	11,425,849	40,769	2,104,018	4,767,583	30,639	36,411,182	2,380,979	38,792,161
17	2030	10,842,546	7,509,619	11,482,556	39,895	2,107,453	4,774,943	30,639	36,787,649	2,408,241	39,195,890
18	2031	11,014,800	7,646,618	11,543,363	39,025	2,110,101	4,782,425	30,639	37,166,969	2,435,695	39,602,664
19	2032	11,191,513	7,789,002	11,599,306	38,913	2,112,684	4,801,643	30,639	37,563,701	2,463,799	40,027,500
20	2033	11,373,936	7,937,717	11,657,704	38,801	2,115,918	4,797,972	30,639	37,952,687	2,492,603	40,445,289

(a) Figures in years -5 thru -1 reflect the impact of energy efficiency programs and have not been weather normalized.
Figures in years 0 thru 20 reflect the impact of energy efficiency programs and are based on weather normal projections.
(b) Sales to wholesale customers.
(c) Line losses and other energy unaccounted for.

Figure 3-C
Duke Energy Indiana
System Peak Load Forecast (Megawatts) (a)

		SUMMER			WINTER (d)		
	YEAR	**LOAD**	**CHANGE (b)**	**PERCENT CHANGE (c)**	**LOAD**	**CHANGE (b)**	**PERCENT CHANGE (c)**
-5	2008	6,243			6,023		
-4	2009	6,037	-206	-3.3	5,602	-421	-7.0
-3	2010	6,476	439	7.3	5,896	294	5.2
-2	2011	6,749	273	4.2	5,603	-293	-5.0
-1	2012	6,494	-255	-3.8	5,763	160	2.9
0	2013	6,516	22	0.3	6,233	470	8.4
1	2014	6,609	93	1.4	6,160	-73	-1.3
2	2015	6,415	-194	-2.9	5,966	-194	-3.1
3	2016	6,533	118	1.8	5,963	-3	0.0
4	2017	6,577	44	0.7	5,915	-51	-0.9
5	2018	6,606	29	0.4	5,865	-50	-0.9
6	2019	6,587	-19	-0.3	5,833	-31	-0.5
7	2020	6,652	64	1.0	5,835	2	0.0
8	2021	6,741	90	1.3	5,878	43	0.7
9	2022	6,832	91	1.4	5,936	58	1.0
10	2023	6,924	92	1.3	5,935	-1	0.0
11	2024	7,019	95	1.4	5,936	1	0.0
12	2025	7,110	90	1.3	5,991	55	0.9
13	2026	7,202	92	1.3	5,967	-24	-0.4
14	2027	7,287	85	1.2	6,043	76	1.3
15	2028	7,386	99	1.4	6,070	27	0.5
16	2029	7,474	89	1.2	6,038	-33	-0.5
17	2030	7,602	127	1.7	6,070	32	0.5
18	2031	7,662	60	0.8	6,145	76	1.2
19	2032	7,761	100	1.3	6,171	26	0.4
20	2033	7,871	109	1.4	6,220	48	0.8

(a) Figures in years -5 thru -1 reflect the impact of historical energy efficiency and demand response, and numbers have not been w eather normalized.
Figures in years 0 thru 20 reflect the impact of energy efficiency, represent peak demand before demand response, and numbers are w eather normal.

(b) Difference betw een reporting year and previous year.

(c) Difference expressed as a percent of previous year.

(d) Winter load reference is to peak loads w hich occur in the follow ing w inter.

Figure 3-D
Duke Energy Indiana
Range of Forecasts

Year	Energy Forecast (Megawatt Hours) (Net Energy for Load) Low	Most Likely	High	Peak Load Forecast (MW) Low	Most Likely	High
2013	36,014,722	36,105,386	36,155,948	6,498	6,516	6,529
2014	36,070,998	36,431,641	36,670,297	6,530	6,609	6,665
2015	33,896,467	34,633,582	35,135,235	6,251	6,415	6,531
2016	34,106,376	35,205,197	35,960,840	6,286	6,533	6,707
2017	34,004,245	35,400,413	36,363,362	6,261	6,577	6,799
2018	33,642,771	35,308,109	36,458,918	6,227	6,606	6,873
2019	33,450,233	35,132,201	36,531,747	6,210	6,587	6,920
2020	33,548,797	35,243,015	36,846,126	6,267	6,652	7,027
2021	33,974,664	35,600,217	37,224,876	6,366	6,741	7,124
2022	34,336,964	36,004,012	37,665,095	6,447	6,832	7,226
2023	34,696,994	36,413,932	38,116,200	6,527	6,924	7,330
2024	34,989,020	36,832,568	38,576,860	6,599	7,019	7,430
2025	35,306,817	37,233,927	39,021,481	6,663	7,110	7,539
2026	35,618,971	37,637,926	39,475,433	6,733	7,202	7,645
2027	35,929,711	38,008,211	39,932,849	6,804	7,287	7,752
2028	36,271,971	38,410,380	40,418,746	6,897	7,386	7,867
2029	36,588,851	38,792,161	40,900,865	6,971	7,474	7,984
2030	36,924,507	39,195,890	41,407,909	7,079	7,602	8,133
2031	37,263,309	39,602,664	41,909,852	7,122	7,662	8,227
2032	37,618,480	40,027,500	42,403,653	7,196	7,761	8,345
2033	37,964,558	40,445,289	42,891,383	7,300	7,871	8,467
2034	38,273,931	40,833,991	43,358,351	7,399	7,991	8,604
2035	38,573,722	41,212,815	43,798,891	7,469	8,080	8,709

Figure 3-E Annual System Energy Scenarios – Megawatthours

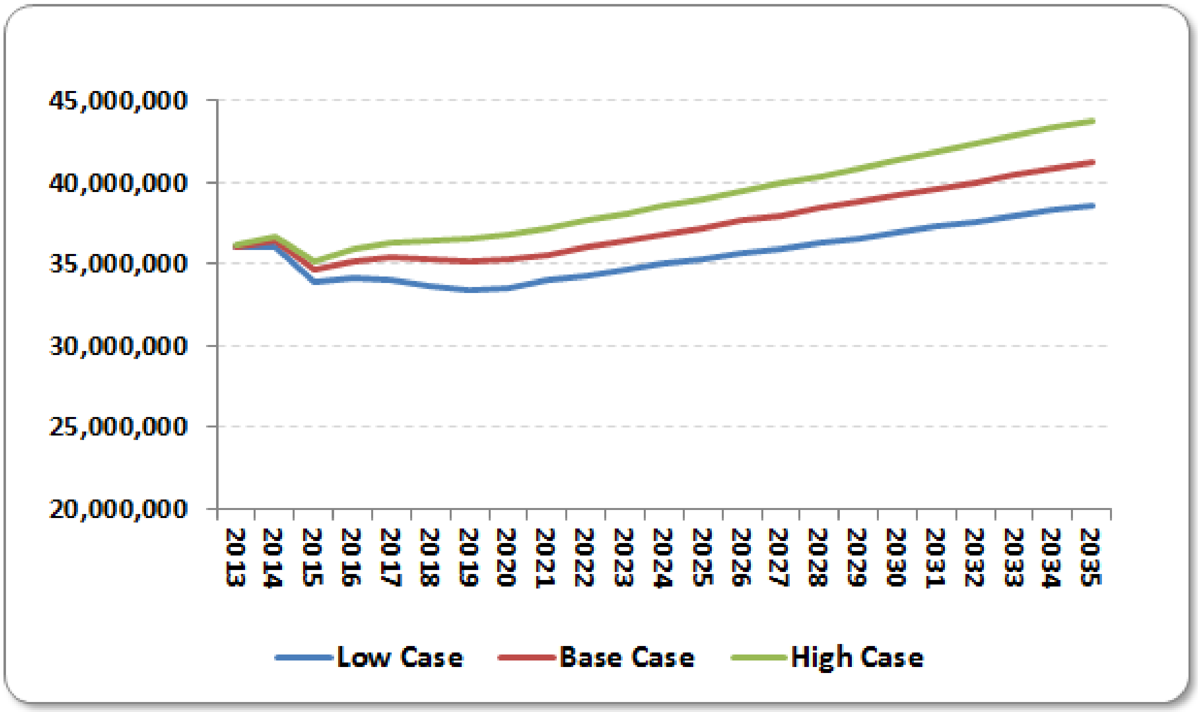
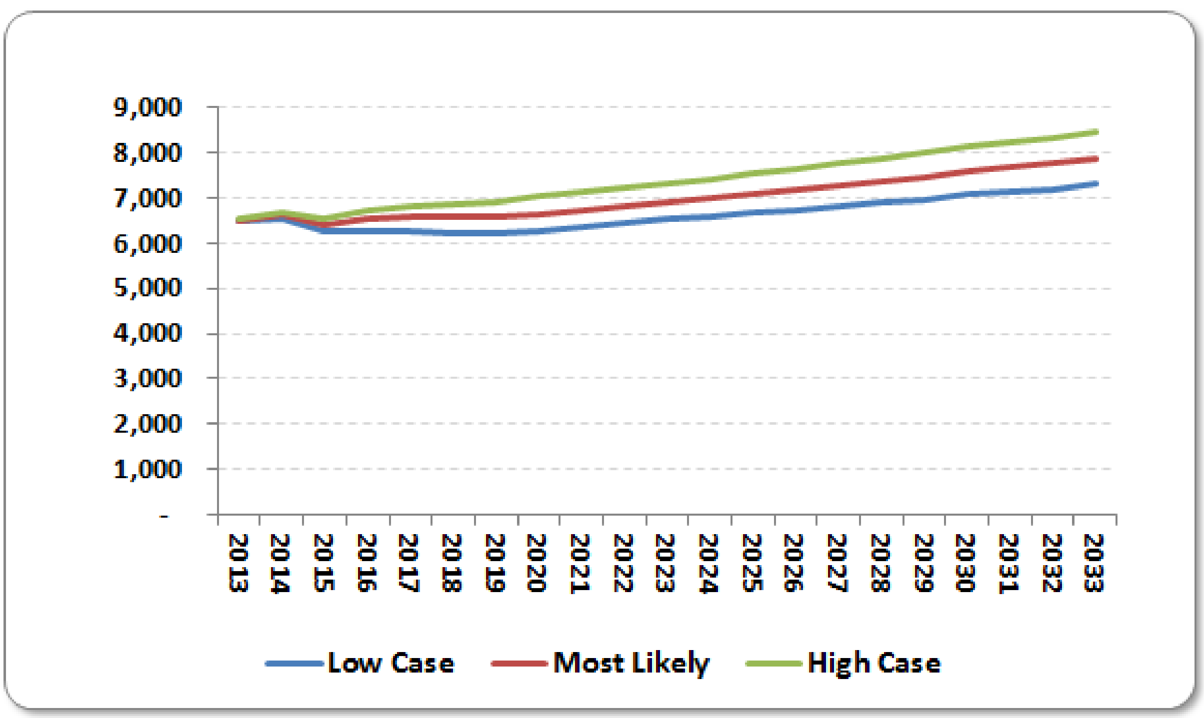


Figure 3-F Annual System Peak Scenarios – Megawatts



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4. ENERGY EFFICIENCY RESOURCES

A. INTRODUCTION

As part of the IRP, Duke Energy Indiana analyzes the impacts associated with new Energy Efficiency (EE) or demand response (DR) programs and any changes in existing EE or DR programs. The portfolio of existing and proposed EE and DR programs is evaluated within the IRP to examine the impact on the generation plan if the current set of programs were to continue and proposed programs were added. Additionally, all proposed and current EE and DR programs are screened for cost-effectiveness as part of the IRP process. The projected incremental load impacts of all programs are then incorporated into the optimization process of the IRP analysis.

B. HISTORY OF DUKE ENERGY INDIANA'S PROGRAMS

Duke Energy Indiana has a long history associated with the implementation of EE and DR programs. Duke Energy Indiana's EE and DR programs have been offered since 1991 and are designed to help reduce demand on the Duke Energy Indiana system during times of peak load and reduce energy consumption during peak and off-peak hours. Demand response programs include customer-specific contract options and innovative pricing programs. Implementing cost-effective EE and DR programs helps reduce overall long-term supply costs. Duke Energy Indiana's EE and DR programs are primarily selected for implementation based upon their cost-effectiveness; however, there may be programs, such as a low income program, that are chosen for implementation due to desirability from an educational and/or social perspective.

C. CURRENT ENERGY EFFICIENCY PROGRAMS

Through a broad set of energy efficiency programs, Duke Energy Indiana expects to reduce energy and demand on the Duke Energy Indiana system. These programs are available for both residential and non-residential customers and include both energy efficiency and demand response programs.

On December 9, 2009, the Commission issued its Phase II Order in Cause No. 42693 ("Phase II Order"). In the Phase II Order, the Commission required that jurisdictional electric utilities offer certain Core Energy Efficiency Programs ("Core Programs") to all customer classes and market segments. To implement these programs, the Commission determined that an independent Third Party Administrator (TPA) should be utilized by the electric utilities to oversee the administration and implementation of the Core Programs. The Commission also established annual gross energy savings targets for all jurisdictional electric utilities and directed utilities to offer Core Plus programs in addition to the Core Program offering.

1. <u>Core Programs</u>

The Core Programs defined in the Commission's Phase II Order are offered through a third-party administrator, as follows:

- **Residential Lighting Program:** Incentives for ENERGY STAR® qualified lighting
- **Low Income Weatherization Program:** Comprehensive energy efficiency retrofits for income-qualified households
- **Energy Efficient Schools Program:** Information and energy efficiency kits for K-12 schools, school building energy audits and access to prescriptive incentives available for commercial customers
- **Commercial and Industrial Program:** Prescriptive incentives for common technologies such as T-8 or T-5 lighting, high efficiency motors and pumps and HVAC equipment
- **Home Energy Audit Program:** Walk-through audits and direct installation of low-cost energy saving measures

2. <u>Core Plus - Residential Programs</u>

The following Core Plus residential programs were approved in Cause No. 43955.

Online Home Energy Calculator

Program**:** This online program assists residential customers in assessing their energy usage and provides recommendations for more efficient use of energy in their homes. The program also helps identify those customers who could benefit most by investing in new energy efficiency measures, undertaking more energy efficient practices, and participating in statewide Core and Duke Energy Indiana Core Plus Programs. To participate in this program, the customer provides information about his/her home, number of occupants, energy usage and equipment through an online energy profile survey. Duke Energy Indiana will provide an online printable report including specific energy saving recommendations.

Eligibility: Available to individually metered residential customers receiving concurrent service from the Company. Online offers will be made through the customer's Online Services Account.

Customer Incentive**:** The Energy Assessment is provided at no cost to the customer. Participants receive a free six-pack of compact fluorescent light bulbs (CFLs).

Personalized Energy Report (PER)™ (closed to new participants starting 2014)

Program: This paper-based assessment assists residential customers in assessing their energy usage and provides recommendations for more efficient use of energy in their homes. The program also will help identify those customers who could benefit most by investing in new energy efficiency measures, undertaking more energy efficient practices, and participating in statewide Core and Duke Energy Indiana Core Plus Programs. The customer provides information about his/her home, number of occupants, equipment, and energy usage on a mailed energy profile survey, from which Duke Energy Indiana will perform an energy use analysis and provide a Personalized Home Energy Report including specific energy saving recommendations through the mail.

Eligibility: Available to individually metered residential customers receiving concurrent service from the Company.

Customer Incentive: The Energy Assessment is provided at no cost to the customer. Participants receive a free six-pack of CFLs.

Smart $aver® for Residential Customers

Program: The Smart $aver® Program provides incentives to customers, builders, and heating contractors (HVAC dealers) to promote and install high-efficiency air conditioners and heat pumps with electronically commutated fan motors (ECM). The program is designed to increase the efficiency of HVAC systems in new homes and for replacements in existing homes.

Eligibility: New or existing owner-occupied residences, condominiums, and mobile homes served by Duke Energy Indiana.

Customer Incentive: Incentives (rebates) will be paid to the builder (new homes) or, for existing homes, part to the homeowner and part to the HVAC contractor.

Agency CFLs – Low Income Services (Agency Assistance Portal & CFLs)

Program: The purpose of this program is to assist low-income residential customers with energy efficiency measures to reduce energy usage by providing free CFLs to income-qualified customers. Customers can request free CFLs when applying for assistance at low income support agencies and have CFLs sent directly to their home.

Eligibility: Customer must meet the financial requirements of the Low Income agency where they are applying for assistance.

Customer Incentive: 12 free CFLs.

Refrigerator and Freezer Recycling

Program: The purpose of this program is to encourage Duke Energy Indiana customers to responsibly dispose of inefficient, but still operating, refrigerators and freezers. Participating customers will have the old unit picked up at their home to be properly recycled/disposed of by the Duke Energy Indiana program vendor.

Eligibility: Duke Energy Indiana customers with normal operating refrigerators/ freezers they are willing to have removed from their home.

Customer Incentive: $30 per refrigerator/ freezer.

Property Manager CFL

Program: Duke Energy Indiana coordinates with property managers to bring energy efficiency to multi-unit residential facilities by providing bulk quantities of CFLs to be installed in individual units. Property Managers will install CFLs in permanent, landlord-owned light fixtures in each rental unit. Property managers will provide a unit-by-unit report of CFLs installed including date of completion. The Program will increase tenant satisfaction with an energy efficient lighting upgrade and educate customers on the advantages of CFLs so they will continue to purchase these bulbs in the future.

Eligibility: Property managers whose facilities are located in Duke Energy Indiana service area are eligible to participate in the program.

Customer Incentive: No cost to the customer. The Property manager will pay the shipping fees for the bulk CFLs.

Tune and Seal

Program: Duke Energy Indiana coordinates with trade allies (HVAC and insulation contractors) to provide energy efficiency services to homeowners in the Duke Energy Indiana service territory. Services available include: duct sealing, electric heating and cooling tune up, attic insulation and attic sealing. The specific mix of beneficial services will vary by customer, but in most cases a bundle of these improvements will be offered to the customer.

Eligibility: Duke Energy Indiana homeowners in the Company's Indiana service area are eligible to participate in the program.

Customer Incentive: The incentive amount will vary by customer depending on which bundle of services offer the most benefit to the customer. The incentive is paid based on the application that is received post installation. An average customer incentive is estimated to be $175.

Home Energy Comparison Report (Pilot program)

Program: Monthly energy usage reports are delivered (email, web or mail) to targeted customers in the Duke Energy Indiana service territory. The report compares household usage to similar, neighboring homes and provides recommendations to lower energy usage. By making customers aware of how their usage compares to similar customers, customers who receive the report will begin to modify their behaviors and become more energy conscious.

Eligibility: Duke Energy Indiana homeowners in the Company's Indiana service area are eligible to participate in the program.

Customer Incentive: None.

Power Manager®

Program: Power Manager® is a residential load control program. The purpose of the Power Manager® program is to reduce demand by controlling residential air conditioning usage during peak demand and high wholesale price conditions, as well as emergency conditions during the summer months. It is available to residential customers with central air conditioning. Duke Energy Indiana attaches a load control device to the outdoor unit of a customer's air conditioner. This enables Duke Energy Indiana to cycle the customer's air conditioner off and on under appropriate conditions.

Eligibility: Power Manager® is offered to residential customers that have a functional central air-conditioning system with an outside compressor unit. Customers must agree to have the control device installed on their A/C system and to allow Duke Energy Indiana to control their A/C system during Power Manager® events.

Customer Incentive: Customers participating in this program receive a one-time enrollment incentive and a bill credit for each Power Manager® event. Customers who select Option A, which cycles their air conditioner to achieve a 1.0 kW load reduction, receive a $25 credit at installation. Customers selecting Option B, which cycles their air conditioner to achieve a 1.5 kW load reduction, receive a $35 credit at installation. The bill credit provided for each cycling event is based on: the kW reduction option selected by the customer, the number of hours of the control event and the value of electricity during the event. For each control season (May through Sept), customers will receive a minimum of $5 in bill credits for Option A and $8 for Option B.

3. Core Plus - Non-Residential Programs

The following Core Plus non-residential programs were approved in Cause No. 43955.

Smart $aver® for Non-Residential Customers

The purpose of this program is to encourage the installation of high-efficiency, ENERGY STAR® certified, where applicable, equipment in new and existing non-residential establishments. The program will provide incentive payments to offset a portion of the higher cost of energy efficient equipment.

Prescriptive Incentive Program: Offers incentives for equipment that supplements the measures offered through the statewide Core Program. The following types of equipment will be eligible for incentives: high-efficiency lighting, high-efficiency HVAC equipment, high-efficiency motors, high efficiency pumps, variable frequency drives, chillers, thermal storage, process equipment, and foodservice equipment. Additional measures may be added for other high-efficiency equipment as determined by the Company to be cost-effective on an ongoing basis.

Custom Incentive Program: Offers incentives for equipment and systems that are not covered by the Prescriptive Incentive or statewide Core Programs. Examples of such systems and equipment include, but are not limited to, large scale applications and for which unique, case-by-case analysis is otherwise required, packaged projects (*i.e.,* whole building design), enhanced building envelopes, as well as high efficiency lighting, HVAC, motors, pumps, variable frequency drives, chillers, thermal storage, process and foodservice equipment/technology that are not covered within the Prescriptive Incentive and Core Programs.

Eligibility: New or existing non-residential facilities served by Duke Energy Indiana.

Customer Incentive: Incentives are available for a percentage of the cost difference between standard equipment and higher efficiency equipment. The Company may vary the percentage incentive by type of equipment and differences in efficiency in order to provide the minimum incentive needed to drive customers to purchase higher efficiency equipment and to encourage additional improvements. Over the life of the program, incentives may be reduced as customers naturally move to purchase higher efficiency equipment.

Non-Residential Energy Assessments

Program: The purpose of this program is to assist non-residential customers in assessing their energy usage and providing recommendations for more efficient use of energy. The program will also help identify those customers who could benefit from other non-residential Duke Energy Indiana Core Plus and statewide Core Programs. The types of available energy assessments are:

- ***Online Analysis:*** The customer provides information about its facility by answering a series of online questions. Based upon the analysis of the customer's responses to the questionnaire, Duke Energy Indiana will provide an energy savings report back to the customer that includes various energy saving recommendations.
- ***Telephone Interview Analysis:*** The customer provides information to Duke Energy Indiana through a telephone interview after which billing data, and, if available, load

profile data, will be analyzed. Duke Energy Indiana will provide an energy analysis report with an efficiency assessment along with recommendations for energy efficiency improvements. A 12-month usage history may be required to perform this analysis.

- ***On-site Audit and Analysis:*** Duke Energy Indiana will cover a portion of the costs of an on-site assessment. Duke Energy Indiana will provide, consistent with the customer's desired level of investment and detail, an energy analysis report. The report will include an efficiency assessment and recommendations for efficiency improvements, tailored to the customer's facility and operation. The Company reserves the right to limit the number of on-site assessments for customers who have multiple facilities on the Duke Energy Indiana system. Duke Energy Indiana may provide additional engineering and analysis if requested and if the customer agrees to pay the full cost of the additional assessment.
- ***Eligibility:*** Available to Duke Energy Indiana non-residential customers.
- ***Customer Incentive:*** The customer's incentive is the professional assessment at a subsidized cost. Customers also will be presented with opportunities to participate in other statewide and Company energy efficiency programs as a result of the assessments.

4. Demand Response Programs

In addition to the Core Plus programs approved in Cause 43955, Duke Energy Indiana also offers the following Demand Response programs under its Rider 70 and other special contracts:

PowerShare® CallOption

Program: PowerShare® CallOption is a non-residential demand response program. The program has components for customers to respond with load curtailment for both emergency and economic conditions and is marketed under the name PowerShare® CallOption. Customers receive capacity credits monthly based on the amount of load they agree to curtail during utility-initiated events triggered by capacity problems. Economic events are triggered on a day-ahead notification based on projections of next day market prices. Customers may "buy through" an economic event by paying the posted hourly price for the day of the event. Emergency events are triggered by MISO and provide customers notification that requires a response within 6 hours. There is no ability to buy through for emergency events.

Eligibility: Available to Customers served under Rates LLF and HLF that can provide at least 100 kW of load curtailment. Customers without load profile metering (less than 500 kW in maximum annual 30-minute demand) must pay the incremental cost of metering. Customers must enter into a service agreement.

Customer Incentive: Program participants will receive capacity credits (premiums) for loads they agree to curtail during program events. The amount of the capacity credit will depend on the offer and level of participation selected by the customer as well as the amount of load response. For actual energy curtailed during an economic event, CallOption customers will receive energy credits (event incentives). The amount of the event incentives will depend on the energy curtailed during the event and the established strike price.

Special Curtailment Contracts

Duke Energy Indiana has contracted with several of its industrial customers to reduce their demand for electricity during times of peak system demand. Currently, two contracts are in effect. These contracts allow Duke Energy Indiana to provide "as available" or "non-firm" service to those customers. Some of these contracts date back to the late 1980s and early 1990s. By the terms of these contracts, Duke Energy Indiana can interrupt those customers at times of system peak, high marginal prices, or during times of system emergencies.

These interruptible contracts contain "buy-through" features except during times of system emergency. The Company currently expects and plans for a 129 MW reduction in the load forecasts for this "as available" load. This is projected to remain available and under contract over the forecast horizon, although there is a risk that customers will not renew the interruptible provisions of their contracts when they expire.

Duke Energy Indiana is currently awaiting approval of an extension of the Core Plus portfolio of EE and DR programs through calendar year 2014, including several new EE measures and a pilot program, Energy Management and Information Services. For the purpose of this IRP, projected impacts from both Core and Core Plus programs, and also new programs to be added in the future, including, but not limited to, those that will be included in the Company's 2015-17 Portfolio filing, were included for 2013 and beyond.

D. PROJECTED IMPACTS

Projected impacts from Core, Core Plus, and demand response programs were included for a 20 year planning horizon from 2013 through 2032. Table 4-A below provides a base case of projected kWh and kW impacts from the Core and Core Plus EE programs, special contracts, and demand response programs. The Reference Scenario (discussed in more detail in Chapter 8) assumes full compliance with the Phase II Order by 2019 and then assumes that impacts keep pace with the growth in the retail sales.

Table 4-A: LOAD IMPACTS OF EE/DR PROGRAMS - BASE CASE

	EE Program Load Impacts		Demand Response Program Load Impacts				
	MWh	MW	MW				Summer Peak
Year	Total MWh	Total MW	PowerShare	Power Manager	Interruptible	Total DR	Total MW
2013	266,737	25.7	324.7	48.0	129.0	501.7	527.4
2014	591,699	77.1	348.7	50.4	129.0	528.1	605.2
2015	974,307	140.0	366.1	54.1	129.0	549.2	689.2
2016	1,416,869	213.4	384.5	54.4	129.0	567.9	781.3
2017	1,923,259	299.0	394.1	54.1	129.0	577.2	876.2
2018	2,492,605	392.0	403.9	53.8	129.0	586.7	978.7
2019	3,092,212	495.9	403.9	53.8	129.0	586.7	1082.6
2020	3,131,144	551.2	403.9	53.8	129.0	586.7	1137.9
2021	3,173,596	559.8	403.9	53.8	129.0	586.7	1146.5
2022	3,214,703	567.2	403.9	53.8	129.0	586.7	1153.9
2023	3,256,338	574.5	403.9	53.8	129.0	586.7	1161.2
2024	3,297,729	549.1	403.9	53.8	129.0	586.7	1135.8
2025	3,339,728	589.4	403.9	53.8	129.0	586.7	1176.1
2026	3,381,550	596.9	403.9	53.8	129.0	586.7	1183.6
2027	3,423,738	604.3	403.9	53.8	129.0	586.7	1191.0
2028	3,467,230	577.1	403.9	53.8	129.0	586.7	1163.8
2029	3,512,322	586.0	403.9	53.8	129.0	586.7	1172.7
2030	3,555,997	593.5	403.9	53.8	129.0	586.7	1180.2
2031	3,597,860	635.3	403.9	53.8	129.0	586.7	1222.0
2032	3,640,311	641.1	403.9	53.8	129.0	586.7	1227.8

The Company also prepared an alternate energy efficiency scenario that provides projected kWh and peak kW impacts if full compliance with the Phase II order is achieved by the end of the planning horizon (Low Regulation Scenario, Table 4-B Low Case below) and a third scenario that assumes full compliance with the Phase II order along with continued significant additional reductions beyond the Phase II order for the period 2020-32 (Environmental Focus Scenario, Table 4-C High Case below).

Table 4-B: LOAD IMPACTS OF EE/DR PROGRAMS - LOW CASE							
	EE Program Load Impacts		Demand Response Program Load Impacts				
	MWh	MW	MW				Summer Peak
Year	Total MWh	Total MW	PowerShare	Power Manager	Interruptible	Total DR	Total MW
2013	266,737	25.7	324.7	47.8	129.0	501.5	527.2
2014	431,065	56.2	314.9	49.7	129.0	493.6	549.8
2015	595,076	85.5	314.9	52.8	129.0	496.7	582.2
2016	760,194	114.5	314.9	52.6	129.0	496.5	611.0
2017	928,107	144.3	314.9	51.7	129.0	495.6	639.9
2018	1,098,557	172.8	314.9	51.0	129.0	494.9	667.7
2019	1,270,971	203.8	314.9	50.7	129.0	494.6	698.4
2020	1,444,947	254.4	314.9	50.7	129.0	494.6	749.0
2021	1,620,304	285.8	314.9	50.7	129.0	494.6	780.4
2022	1,797,044	317.1	314.9	50.7	129.0	494.6	811.7
2023	1,975,218	348.5	314.9	50.7	129.0	494.6	843.1
2024	2,154,871	358.8	314.9	50.7	129.0	494.6	853.4
2025	2,335,973	412.3	314.9	50.7	129.0	494.6	906.9
2026	2,518,535	444.6	314.9	50.7	129.0	494.6	939.2
2027	2,702,551	477.0	314.9	50.7	129.0	494.6	971.6
2028	2,888,030	480.7	314.9	50.7	129.0	494.6	975.3
2029	3,074,992	513.0	314.9	50.7	129.0	494.6	1007.6
2030	3,263,494	544.7	314.9	50.7	129.0	494.6	1039.3
2031	3,453,557	609.8	314.9	50.7	129.0	494.6	1104.4
2032	3,645,139	642.0	314.9	50.7	129.0	494.6	1136.6

Table 4-C: LOAD IMPACTS OF EE/DR PROGRAMS - HIGH CASE							
	EE Program Load Impacts		Demand Response Program Load Impacts				
	MWh	MW	MW				Summer Peak
Year	Total MWh	Total MW	PowerShare	Power Manager	Interruptible	Total DR	Total MW
2013	266,737	25.7	324.7	48.3	129.0	502.0	527.7
2014	591,699	77.1	365.4	51.6	129.0	546.0	623.1
2015	974,307	140.0	392.8	55.8	129.0	577.6	717.6
2016	1,416,869	213.4	412.4	56.7	129.0	598.1	811.5
2017	1,923,259	299.0	433.0	56.9	129.0	618.9	917.9
2018	2,492,605	392.0	454.6	57.1	129.0	640.7	1032.7
2019	3,092,212	495.9	454.6	57.2	129.0	640.8	1136.7
2020	3,199,399	563.2	454.6	57.2	129.0	640.8	1204.0
2021	3,306,568	583.3	454.6	57.2	129.0	640.8	1224.1
2022	3,414,280	602.4	454.6	57.2	129.0	640.8	1243.2
2023	3,523,162	621.6	454.6	57.2	129.0	640.8	1262.4
2024	3,633,243	605.0	454.6	57.2	129.0	640.8	1245.8
2025	3,744,509	660.8	454.6	57.2	129.0	640.8	1301.6
2026	3,856,966	680.8	454.6	57.2	129.0	640.8	1321.6
2027	3,970,611	700.8	454.6	57.2	129.0	640.8	1341.6
2028	4,085,452	680.0	454.6	57.2	129.0	640.8	1320.8
2029	4,201,501	701.0	454.6	57.2	129.0	640.8	1341.8
2030	4,318,798	720.8	454.6	57.2	129.0	640.8	1361.6
2031	4,437,355	783.5	454.6	57.2	129.0	640.8	1424.3
2032	4,557,149	802.6	454.6	57.2	129.0	640.8	1443.4

E. EXISTING ENERGY EFFICIENCY PROGRAMS, HISTORICAL PERFORMANCE

Duke Energy Indiana has been aggressive in the planning and implementation of energy efficiency programs. As a result of the energy efficiency efforts through the year 2012, Duke Energy Indiana has reduced summer peak demand by a projected 232 MW and annual energy use by 1,025 gigawatt-hours (GWh). These load reductions do not include the impacts of any demand response programs, including the Power Manager direct load control program, interruptible contracts, or the PowerShare® program.

The forecast of loads provided in Chapter 3 incorporates the effects of these historical impacts in the baseline forecast.

F. PROGRAM SCREENING, ASSUMPTIONS, AND DATA SOURCES

All Core Plus EE and DR programs are evaluated for consideration of inclusion in the Integrated Resource Plan using the DSMore software and must be cost-effective.

1. DSMore

DSMore is a financial analysis tool designed to help energy efficiency and demand response program planners evaluate the costs, benefits, and risks of energy efficiency programs and measures and has been used to assess the cost-effectiveness of the Core programs across the state of Indiana.

At a high level, DSMore is used to create estimates of the avoided costs (benefits) from the implementation of energy efficiency programs and measures and compare them to the costs of implementation for an assessment of the cost-effectiveness. DSMore can be utilized to estimate the value of an energy efficiency measure at an hourly level across a wide variety of weather and energy cost conditions. This enables the user to obtain a better understanding of the risks and benefits of employing energy efficiency measures. Understanding the manner in which energy efficiency cost effectiveness varies under alternate conditions allows a more precise valuation of energy efficiency and demand response programs.

2. Cost-Effectiveness Tests

The cost-effectiveness tests are calculated by comparing the net present values of streams of financial costs vs. benefits. The programs are valued against the avoided costs. The resultant benefit/cost ratios, or tests, provide a summary measure of the program's cost effectiveness and its projected load impacts. In general, the criteria used for screening energy efficiency programs for Duke Energy Indiana is the Utility Cost Test (UCT), which compares utility benefits to utility costs and does not consider other benefits such as participant savings or societal impacts.

To reflect the impacts of the overall energy efficiency activity, all program impacts are summed together and incorporated into the IRP modeling analysis (see Chapter 8). Further information on the estimated costs of the programs may be found in the Short-Term Implementation Plan. Table 4-D summarizes the cost-effectiveness results for the Core Plus Programs as filed and approved in Cause No. 43955.

Table 4-D: Program Cost Effectiveness Test Results of Core Plus Programs

RESIDENTIAL CUSTOMER PROGRAMS	**UCT**	**TRC**	**RIM**	**Participant**
Online Home Energy Calculator	2.05	2.96	0.92	-
Personalized Energy Report	2.90	4.86	1.10	-
Smart$aver for Residential Customers - Central Air Conditioner	1.62	1.23	1.00	1.69
Smart$aver for Residential Customers - Heat Pump	3.67	2.78	1.57	2.97
Agency CFLs - Low Income Services (Agency Assitance Portal & CFLs)	4.75	13.21	1.25	-
Refrigerator Recycling	3.14	3.73	1.34	-
Freezer Recycling	1.58	1.77	0.95	-
Property Manager CFL	4.10	9.11	1.24	-
Tune and Seal	1.49	7.72	0.94	-
Home Energy Comparison Report	2.14	2.14	1.04	-
Power Manager	4.36	6.28	4.36	-
NON-RESIDENTIAL CUSTOMER PROGRAMS				
Smart$aver for Non-Residential Customers - HVAC	5.17	2.48	1.89	1.83
Smart$aver for Non-Residential Customers - Lighting	5.40	2.20	1.34	2.40
Smart$aver for Non-Residential Customers - Motors/Pumps/VFD	15.06	3.47	1.65	3.15
Smart$aver for Non-Residential Customers - Food Service	7.77	2.01	1.43	2.05
Smart$aver for Non-Residential Customers - Process Equipment	14.23	8.72	1.52	9.70
Smart$aver for Non-Residential Customers - Custom	7.73	1.88	1.46	1.89
Non-Residential Energy Assessments[1]	N/A	N/A	N/A	N/A
PowerShare CallOption	3.95	38.56	3.95	-

1 - Non-Residential Energy Assesments do not offer direct benefits, therefore Cost Effectiveness Tests do not apply

Results above are from the Core Plus filing approved in Cause No. 43955

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5. SUPPLY-SIDE RESOURCES

A. INTRODUCTION

The phrase "supply-side resources" encompasses a wide variety of options that Duke Energy Indiana uses to meet the energy needs of its customers, both reliably and economically. These options can include existing generating units, repowering options for these units, existing or potential power purchases, and new utility-owned generating units (conventional, advanced technologies, and renewables). The IRP process assesses the possible supply-side resource options that would be appropriate to meet the system needs by considering their technical feasibility, fuel availability and price, length of the contract or life of the resource, construction or implementation lead time, capital cost, operation and maintenance (O&M) cost, reliability, and environmental effects. This chapter will discuss in detail the specific options considered, the screening processes utilized, and the results of the screening processes.

B. EXISTING UNITS

1. Description

The total installed net summer generation capability owned or purchased by Duke Energy Indiana is currently 7,503 MW.[7] This capacity consists of 4,765 MW of coal-fired steam capacity, 595 MW of syngas/natural gas combined cycle capacity, 285 MW of natural gas-fired combined cycle capacity, 45 MW of hydroelectric capacity, and 1,804 MW of natural gas-fired or oil-fired peaking capacity. Also included is a power purchase agreement with Benton County Wind Farm (100 MW, with 9 MW contribution to peak modeled).

The coal-fired steam capacity consists of 14 units at four stations (Gibson, Cayuga, Gallagher and Wabash River). The syngas/natural combined cycle capacity is comprised of two syngas/natural gas-fired combustion turbines and one steam turbine at the Edwardsport IGCC station. The combined cycle capacity consists of a single station comprised of three natural gas-fired combustion turbines and two steam turbines at the Noblesville Station. The

[7] Excluding the ownership interests of Indiana Municipal Power Agency (IMPA) (155 MW) and Wabash Valley Power Association, Inc. (WVPA) (155 MW) in Gibson Unit 5, and the ownership interest of WVPA (213 MW) in Vermillion, but including the non-jurisdictional portion of Henry County (50MW) associated with a long-term contract.

hydroelectric generation is a run-of-river facility comprised of three units at Markland on the Ohio River. The peaking capacity consists of seven oil-fired diesels located at Cayuga and Wabash River, seven oil-fired CT units located at Connersville and Miami-Wabash, and 24 natural gas-fired CTs located at five stations (Cayuga, Henry County, Madison, Vermillion, and Wheatland). One of these natural gas-fired units has oil back-up. Duke Energy Indiana also provides steam service to one industrial customer from Cayuga, which reduces Duke Energy Indiana's net capability to serve electric load by approximately 20 MW.

The largest units are the five Gibson units at approximately 620-630 net MW each, and the two Cayuga units at approximately 500 MW each. The smallest coal-fired units on the system are the three 85 MW Wabash River units. The large variation in unit size of the coal-fired units on Duke Energy Indiana's system is mainly due to the vintage of the units.

The peaking units range in size from 2-3 MW oil-fired internal combustion units at Wabash River and Cayuga to 115 MW natural gas-fired CTs at Wheatland.

Information concerning the existing generating units as of the date of this filing is contained in Table 5-A. This table lists the name and location of each station, unit number, type of unit, installation year, net dependable summer and winter capability (Duke Energy Indiana share), and current environmental protection measures.

The net dependable summer and winter capability (Duke Energy Indiana share) by plant is shown in Appendix F in Table F-4. A listing of the units grouped by fuel type (*i.e.*, coal, syngas, gas, oil, water and wind) is shown in Appendix F in Table F-5. Tables F-3, F-4 and F-5 are standardized templates agreed upon by the Indiana utilities involved in the IRP Investigation, docketed as Cause No. 43643. The approximate fuel storage capacity at each of the coal- and oil–fired generating stations is shown in Figure A-6 in Appendix A.

Long term purchases are shown in Figure A-7 in Appendix A. Duke Energy Indiana has contracted with Benton County Wind Farm for a 20 year wind PPA for 100 MW (9 MW capacity value modeled) expiring April 2028.

2. Availability

The unplanned outage rates of the units used for planning purposes were derived from the historical Generating Availability Data System (GADS) data on these units. Planned outages were based on maintenance requirement projections as discussed below. This IRP assumes the Duke Energy Indiana generating units generally will continue to operate at their present availability and efficiency (heat rate) levels. However, adjustments to present operating conditions were made for future environmental controls.

3. Maintenance Requirements

A comprehensive maintenance program is important in providing reliable, low-cost service. The general guidelines governing the preparation of a maintenance schedule for existing units are shown below. It is anticipated that future units will be governed by similar guidelines.

- ***Base load units 400 MW and larger:*** 6 to 12 year intervals (Cayuga 1-2, Gibson 1-5, and Edwardsport IGCC).
- ***Intermediate-duty units between 140 MW and 400 MW***: 6 to 15 year intervals (Noblesville Repowering).
- ***Limited run-time peaking and small coal units***: Judgment and predictive maintenance will be used to determine the need for major maintenance (Cayuga 3&4, Madison 1-8, Henry County 1-3, Wheatland 1-4, Vermillion 1-8, Connersville 1-2, Miami-Wabash 1-3&5-6, Gallagher 2&4, and Wabash River 2-6).

In addition to the regularly scheduled maintenance outages, Duke Energy Indiana continues the maintenance program during "availability outages." Availability outages are unplanned, opportunistic, proactive short duration outages aimed at addressing summer reliability. At appropriate times, when it is economic to do so, units may be taken out of service for generally short periods of time (*i.e.*, less than nine days) to perform maintenance activities. This enhancement in the maintenance philosophy reflects the focus on ensuring generation is available during peak periods (*e.g.*, the summer months). Generating station performance is now measured primarily by plant availability during higher price time frames. Moreover, targeted, plant-by-plant assessments have been performed annually to determine the causes of all forced outages which enable the Company to better focus actions during maintenance and availability outages. Finally, system-wide and plant-specific contingency planning was instituted to ensure an adequate supply of labor and materials when needed, with the goal of reducing the length of any forced outages.

The general maintenance requirements for all of the existing generating units were entered into the models used to develop the IRP.

4. Fuel Supply

Duke Energy Indiana generates energy to serve its customers through a diverse mix of fuels consisting primarily of coal, syngas, natural gas, and fuel oil. The Company has access to a broader array of fuels through its participation in the MISO market, which encompasses a variety of generation sources in more than 12 Midwestern states[8].

The Company continues to generate a majority of its energy using coal, with usage dictated by the relative prices of coal as compared against the alternative fuel options in the economic dispatch process. The percentages of Duke Energy Indiana's generating capacity shown in Table F-5 in Appendix F by fuel type are 64% coal, 8% syngas, 25% natural gas, 2% oil, and 1% hydro.

Coal

Over 80% of Duke Energy Indiana’s total energy is generated from burning coal. In evaluating any purchase of coal for use by Duke Energy Indiana, the Fuels Department considers three primary factors: (1) the reliability of supply in quantities sufficient to meet Duke Energy Indiana generating requirements, (2) the quality required to meet environmental regulations and/or manage station operational constraints, and (3) the lowest reasonable cost as compared to other purchase options. The “cost” of the coal is defined as the purchase price at the delivery point, plus the transportation costs to get the coal to the applicable station, plus the evaluated sulfur content, and finally the evaluated economic impacts of the coal quality on station operations.

[8] The Entergy region of Arkansas, Louisiana, and portions of Mississippi and Texas will be integrated into MISO at the end of 2013.

To aid in fuel supply reliability, fuel procurement policies (*e.g.* contract versus short term ratios, inventory target levels) guide decisions on when the Fuels Department should enter the market to procure certain quantities and types of fuel for the stations. These policies are viewed in the context of economic and market forecasts and probabilistic dispatch models to collectively provide the Company with a five-year strategy for fuel purchasing. The strategy provides a guide to meet the goal of having a reliable supply of low cost fuel.

To enhance fuel supply reliability and mitigate supply risk, Duke Energy Indiana purchases coal from multiple mines in the geographic area of our stations. Stockpiles of coal maintained at each station to guard against short-term supply disruptions. In determining the amount of inventory to maintain at each station, the Company evaluates the probability of disruptions and the possible duration of events that will affect the coal supply. This evaluation process balances the cost of sufficient coal supply at each station against the risk of supply disruptions.

Currently, coal supplied to the base load coal stations comes primarily from Indiana and Illinois. These states are rich in coal reserves with decades of remaining economically recoverable reserves. Over 90% of the coal supplied to Duke Energy Indiana's base load stations is currently under long-term contracts. Prior to entering long-term commitments with coal suppliers, the Company evaluates such things as the financial stability, performance history, mining plans, estimated reserves and overall reputation of the suppliers. By entering into long-term commitments with suppliers, Duke Energy Indiana further protects itself from risk of insufficient coal availability while also giving suppliers the needed financial stability to allow them to make capital investments in the mines and hire the labor force. If the Company were to try to purchase all of its requirements on the short-term open market, the Company likely would have severe difficulties in finding sufficient coal for purchase to meet our needs due to the inability of the mines to increase production to accommodate 10-12 million annual tons in such a short timeframe. The current Duke Energy Indiana supply portfolio includes six long-term coal supply agreements. Under these contracts, the Company buys the coal at the mine. Thus, the contracts do not restrict our ability to move the coal to the various Duke Energy Indiana coal-fired generating stations as necessary to meet generation requirements.

This arrangement allows for greater flexibility in meeting fluctuations in generating demand and any supply or transportation disruptions.

For low capacity factor coal stations such as Gallagher and Wabash River, we are pursuing a much shorter term procurement policy due to existing environmental compliance requirements (*e.g.* NSR), the uncertainties around future environmental regulations (*e.g.* MATS and NAAQS) and the potential for retirement of these aging units. Currently, we are sourcing low-sulfur coal for these intermediate stations on a short-term basis, typically one-year or less, from such places as Colorado, Wyoming, Indiana and West Virginia.

Duke Energy Indiana fills out the remainder of its fuel needs for both base load and intermediate load stations with spot coal purchases. Spot coal purchases are used to 1) take advantage changing market conditions that may lead to low-priced incremental tonnage, 2) test new coal supplies, and 3) supplement coal supplies during periods of increased demand for generation or during contract delivery disruptions.

Coal Price Scenarios and Sensitivities

Duke Energy Corporation (Duke Energy) employed Energy Ventures Analysis, Inc. (EVA) to produce Duke Energy's fully integrated fuel and energy Fundamental Forecast for the IRP scenarios. Among many factors, this forecast captures the interplay between gas and coal as well as inter-basin competition among coals, along with all logistics to move the fuels to their respective combustion points, to arrive at the least cost solution to meet energy needs over the long-term. The high coal sensitivity relative to the Duke Energy Fundamental Forecast is +25%; the low sensitivity is -15%. This sensitivity range was derived by comparing the 2013 Duke Energy Fundamental Forecast base case (used in the Reference Scenario) with contemporary basin level forecasts (2012 and 2013) of multiple nationally recognized energy advisory groups (EIA, EVA, PIRA, Wood-Mackenzie). Most of these forecasts are underpinned with assumptions which can be different from those of the Duke Energy case; however, we value these views, especially in validation of the Duke Energy case and in establishment of likely high and low ranges. The asymmetric nature of the range is a result of the Duke Energy Fundamental Forecast being near the cash costs of the coal producers in the aggregate – in other words, there is not a lot of downside. On the other hand, as production picks up to meet the higher demand in the Low Regulation Scenario, the price response is significant.

Natural Gas

The use of natural gas by Duke Energy Indiana for electric generating purposes has generally been limited to CT and CC applications. Natural gas is currently purchased on the spot market and is typically transported (delivered) using interruptible transportation contracts or as a bundled delivered product (spot natural gas plus transportation), although the company does have firm transportation contracts on the Midwestern Gas pipeline for gas delivery to Edwardsport, Vermillion, and Wheatland. The future CC fuel cost incorporates both the natural gas commodity price and firm transportation cost, and the future CT fuel cost includes the natural gas commodity price and interruptible transportation cost.

Outlook for Natural Gas

Following a tumultuous year for North American gas producers, 2013 is signaling a return to market stability. Near term prices have recovered from their sub $2/MMBtu lows to settle into the $3.50 - $4.00 range. Although inventories are back in neutral territory and gas-directed rig counts remain at 18-year lows, the size of the low cost resource base continues to expand. Looking forward, the gas market is expected to remain relatively stable and the improving economic picture will allow the supply/demand balance to tighten with prices continuing to firm at sustainable levels. New gas demand from the power sector is likely to get a small boost between now and 2015 from coal retirements tied to the implementation of the EPA MATS rule regulating mercury and acid gasses. This increase is expected to be followed by new demand in the industrial and LNG export sectors which ramp up in the 2016 – 2020 timeframe.

Risks to the Outlook

Although environmental risks associated with on-shore shale production remain, the fear of new potentially cost-prohibitive federal regulations related to hydraulic fracturing has eased a bit with some early favorable reporting on a highly anticipated DOE study in the Marcellus. Although the results of this study conducted by the National Energy Technology Laboratory (NETL) are still being compiled, the early reporting suggests that fluids used in the hydraulic fracturing process are unlikely to migrate upward and contaminate the drinking water tables. A statement just released by NETL indicated that, while nothing of concern has been detected in any of the monitored test wells, final judgment should be withheld until the report is released at the end of 2013. NETL also has several other studies underway to look at other aspects of the shale production process, but this Marcellus study was absolutely critical for the industry to demonstrate the safety of the fracturing process with regard to drinking water wells. These reports come after a Duke University study conducted in the Fayetteville (AR) shale production zone, which found no contamination in the 127 private water wells they tested. Similarly, the EPA has just dropped its investigation into the Pavillion, WY water well contamination claims and has turned its findings over to state regulators. The EPA is monitoring a number of studies and will release a final report to Congress in 2014 which will likely serve as the basis for any new federal regulations.

Gas Price Scenarios and Sensitivities

EVA was the primary consultant for the 2013 Duke Energy fundamental outlook. The Duke Energy Reference Case is differentiated from the EVA outlook as a result of several input assumption changes suggested by Duke Energy. These changes include: adding a price on carbon, higher levels of renewable energy technologies in several of the Duke Energy jurisdictional states, and generation capital and O&M cost assumptions. These changes requested by Duke Energy were primarily in the power sector which impacted the demand for natural gas and, by extension, the price of gas and power at the margin.

In addition to the Reference Scenario, Duke Energy requested that EVA perform the same comprehensive analysis for the Environmental Focus and the Low Regulation scenarios. These two scenarios also centered on the power sector demand for fuels under different market conditions and resulted in lower and higher demand and prices for gas, respectively. All of these cases relied on EVA's proprietary database, knowledge of the upstream US gas supply base, and their integrated fundamental modeling framework for price discovery.

In addition to the Reference Scenario and the two alternative scenarios, the Duke Energy Fundamentals team developed a range of gas prices to use as high and low sensitivities. The sensitivity range is meant to reflect the long term uncertainty band around the average price over the forecast horizon. It is not meant to capture all the possible short term price deviations. To develop the sensitivity range, Duke Energy evaluated nine contemporary gas price forecasts by leading energy consultants. Duke Energy recognizes the value of considering varying points of view in its commodity price forecasting process. These nine outlooks each contain unique assumptions about the future and each forecast arrived at different price outcomes. To determine the size of our uncertainty band, Duke Energy established the boundary conditions as being two standard deviations above and below the mean for the group. Because the Duke Energy gas price forecast was above the mean for the entire group, the resulting uncertainty band relative to the Duke Energy forecast appears asymmetrical relative to it and can be approximated by the function: Duke Energy gas price +15%, and Duke Energy gas price -21%.

Oil

Duke Energy Indiana uses fuel oil for starting coal-fired boilers and for flame stabilization during low load periods. Some CT peaking facilities are oil-fired. Cayuga Unit 4 uses oil as a back-up fuel. Oil supplies, purchased on an as-needed basis, are expected to be sufficient to meet needs for the foreseeable future.

5. Fuel Prices

Fuel prices for both existing and new units were developed using a combination of observable forward market prices and longer term market fundamentals. EVA performed the long term fundamentals analysis with input from Duke Energy subject matter experts. The projected fuel prices are considered by Duke Energy Indiana and EVA to be trade secrets and proprietary competitive information.

6. Condition Assessment

Duke Energy Indiana continues to implement its engineering condition assessment programs. The intent is to maintain the generating units at their current levels of efficiency and reliability when economically feasible.

The older CT units at Miami-Wabash and Connersville were assumed to retire in 2018. Each CT is tested once per year to meet MISO reliability requirements. Given the age of these turbines, if significant maintenance is required to meet the reliability requirements, the retirement decision on a specific unit could accelerate. As an example, Miami-Wabash Unit 4 was retired in 2010 following generator equipment failures.

7. Efficiency

Duke Energy Indiana evaluates the cost-effectiveness of maintenance options on various individual components of the existing generating units. If the potential maintenance options prove to be cost-justified and pass a New Source Review (NSR) screen, they are budgeted and generally undertaken during a future scheduled unit maintenance outage.

Duke Energy Indiana routinely monitors the efficiency and availability of its generating units. Based on those observations, projects that are intended to maintain long-term performance are planned, evaluated, selected, budgeted, and executed. Such routine periodic projects might include, but were not limited to, turbine-generator overhauls; condenser cleanings and condenser system repairs, such as vacuum pump and circulating water pump rebuilds; burner replacements, coal pulverizer overhauls, and combustion system tuning; secondary air heater basket material replacements; boiler tube section replacements; and pollution control equipment maintenance, such as selective catalytic reduction (SCR) catalyst replacement and flue gas desulfurization (FGD) limestone slurry pump rebuilds. In addition, Duke Energy Indiana looks for opportunities to improve the overall performance of the units, including targeted projects for generating unit efficiency improvements.

Any plans to increase fossil fuel generation efficiency must be viewed in light of regulatory requirements, specifically the NSR rules defined by the EPA. These regulatory requirements are subject to interpretation and change over the years. Within the context of such requirements, Duke Energy Indiana plans routine maintenance projects, which may maintain or increase the efficiency of its generating units.

C. EXISTING NON-UTILITY GENERATION

Some Duke Energy Indiana customers have electric production facilities for self-generation, peak shaving, or emergency back-up. Non-emergency self-generation facilities are normally of the baseload type and are generally sized for reasons other than electric demand (*e.g.*, steam or other thermal demands of industrial processes or heating). Peak shaving equipment is typically oil- or gas-fired and generally is used only to reduce the peak billing demand. Depending on whether it is operated at peak, this capacity can reduce the load otherwise required to be served by Duke Energy Indiana which, like Demand Response programs, also reduces the need for new capacity.

D. EXISTING POOLING AND BULK POWER AGREEMENTS

Duke Energy Indiana is directly interconnected with seven other local balancing authorities (American Electric Power, Louisville Gas and Electric Energy, Ameren, Hoosier Energy, Indianapolis Power and Light, Northern Indiana Public Service Company, and Vectren), plus Duke Energy Ohio.

Duke Energy Indiana participates in the MISO energy markets. MISO ensures the safe, cost-effective delivery of electric power across all or parts of 12 Midwest states.[9] As a Regional Transmission Organization (RTO), MISO assures consumers of unbiased regional grid management and open access to the transmission facilities under MISO's functional supervision.

Duke Energy Indiana co-owns Gibson Unit 5 with WVPA and IMPA, and currently provides Reserve Capacity and Back-up Energy for this unit. The modeling for this Reserve Capacity and Reserve Energy consists of representing 100% of Gibson 5 capacity and including the load for WVPA and IMPA that corresponds to their capacity shares at 100% load factor through December 31, 2014, when the contract expires. Duke Energy Indiana periodically meets with WVPA and IMPA to discuss the operation of Gibson 5.

Duke Energy Indiana has several bulk power agreements currently in place. These agreements allow Duke Energy Indiana to provide/purchase energy and/or capacity to/from other utilities or facilities.

- WVPA - As part of the Marble Hill settlement between WVPA and Duke Energy Indiana, Duke Energy Indiana has a contract to provide 70 MW of firm capacity and energy to WVPA

[9] The Entergy region of Arkansas, Louisiana, and portions of Mississippi and Texas will be integrated into MISO at the end of 2013.

for up to 35 years (*i.e.*, through 2032). There are also contracts to provide 50 MW of firm capacity and energy through 2025 and 150 MW of firm capacity and energy through 2026.

- IMPA - Duke Energy Indiana has a contract to provide IMPA with 50 MW of firm capacity and energy through May 31, 2017.
- Hoosier Energy - Duke Energy Indiana has two 100 MW contracts to provide firm capacity and energy to Hoosier Energy. The period of the first contract is through December 31, 2017, and the second is through December 31, 2023. A third contract to provide 50 MW of firm capacity and energy to Hoosier Energy is scheduled to begin on January 1, 2016, and ends on December 31, 2025.
- Henry County Station– Duke Energy Indiana has a 20-year, 50 MW contract with WVPA associated with the Henry County Station, which reduces the capacity available for Duke Energy Indiana native load customers at this station by this amount. (This 50 MW has been jurisdictionalized out of Duke Energy Indiana's retail rates).
- Benton County Wind Farm - The Company has a contract to purchase the energy produced by 100 MW of wind turbines from the Benton County Wind Energy Project (See Section G later in this chapter).
- Logansport - Effective July 1, 2009, Duke Energy Indiana purchased all of the Logansport Unit #6 capacity (approximately 8 MW) from the City of Logansport. The contract agreement is scheduled to end December 31, 2018. Logansport notified Duke Energy Indiana in summer 2011 that this unit was unavailable and it remains unavailable at this time.
- Other - Duke Energy Indiana has both full and partial requirements contracts to serve a number of municipals in Indiana, although some of these cities elected to join IMPA, which terminated their contracts with Duke Energy Indiana.

With the exceptions of the Gibson 5 Reserve Capacity and Energy contract and 20 MW of six small municipal contracts, all of the wholesale load obligations are modeled as firm load throughout the study period, which assumes that these contracts will be renewed or replaced with new contracts.

Additionally, Duke Energy Indiana routinely executes energy hedge trades, which provide Duke Energy Indiana price certainty and reduce customers' exposure to energy price volatility. Further information concerning power purchase contracts may be found in the Short-Term Implementation Plan contained in Appendix E.

E. <u>NON-UTILITY GENERATION AS FUTURE RESOURCE OPTIONS</u>

It is Duke Energy Indiana's practice to cooperate with potential combined heat and power (CHP) projects, *i.e.*, cogenerators, and independent power producers. However, a major concern exists in situations where customers would be subsidizing generation projects through higher than avoided cost buyback rates, or the safety or reliability of the electric system would be jeopardized. Duke Energy Indiana typically receives several requests each year for independent/small power production and cogeneration buyback rates. Prospective cogenerators are given the interconnection requirements and the current rates under Standard Contract Rider No. 50 - Parallel Operation for Qualifying Facility.

A customer's decision to self-generate or cogenerate is, of course, based on economics. Customers know their costs, profit goals, and competitive positions. The cost of electricity is just one of the many costs associated with the successful operation of their business. If customers believe they can lower their overall costs by self-generating, they will investigate this possibility on their own. Cogeneration and small power production are generally uneconomical for most customers.

For these reasons, Duke Energy Indiana does not attempt to forecast specific megawatt levels of this activity. Cogeneration facilities built to affect customer energy and demand served by the utility are captured in the load forecast. Cogeneration built to provide supply to the electric network represents additional regional supply capability. As purchase contracts are signed, the resulting energy and capacity supply will be reflected in future plans. Portions of the projections for renewables and EE in this IRP can be viewed as placeholders for these types of projects.

Other supply-side options such as CTs, CCs, coal-fired units, and/or renewables could represent potential non-utility generating units, power purchases, or utility-owned units. At the time when Duke Energy Indiana initiates the acquisition of new capacity, a decision will be made as to the best source.

F. SUPPLY-SIDE RESOURCE SCREENING

In the screening analysis, a diverse range of technology choices utilizing a variety of different fuels was considered including pulverized coal (PC) units with and without carbon capture and storage (CCS), IGCC with and without CCS, CTs, CCs, and nuclear units. In addition, wind, solar, and biomass renewable technologies were evaluated.

For the 2013 IRP screening analyses, technology types were screened within their own general category of baseload, peaking/intermediate, and renewable. The ultimate goal of the screening process was to pass the best alternatives from each of these three categories to the integration process, as opposed to having all renewable technologies screened out because they did not fare well against the more conventional technologies on the final screening curve. The reason for performing these initial screening analyses is to determine the most viable and cost-effective resources for further evaluation. This is necessary because of the size of the problem to be solved and computer execution time limitations of the System Optimizer capacity planning model (described in detail in Chapter 8).

1. Process Description

Information Sources

The cost and performance data for each technology being screened is based on research and information from several sources. These sources include, but may not be limited to the following: Duke Energy's New Generation Project Development, Emerging Technologies, and Analytical Engineering; the EPRI Technology Assessment Guide (TAG®); and studies performed by and/or information gathered from external sources. In addition, fuel and operating cost estimates are developed internally by Duke Energy, or from other sources such as those mentioned above, or a combination of these. EPRI information or other information or estimates from external studies are not site-specific, but generally reflect the costs and operating parameters for installation in the Carolinas.

Finally, every effort is made to ensure that cost and other parameters are current and include similar scope across the technologies being screened. While this has always been important, keeping cost estimates across a variety of technology types consistent in today's markets for commodities, construction materials, and manufactured equipment is challenging.

Technical Screening

The first step in the Company's supply-side screening process for the IRP is a technical screening of the technologies to eliminate those that have technical limitations, commercial availability issues, or are not feasible in the Duke Energy Indiana service territory. A brief explanation of the technologies excluded at this point and the basis for their exclusion follows:

- ***Geothermal*** was eliminated because there are no suitable geothermal resources in the region to develop into a power generation project.
- ***Advanced energy storage technologies*** (Lead acid, Li-ion, Sodium Ion, Zinc Bromide, Fly wheels, pumped storage, etc.) remain relatively expensive, as compared to conventional generation sources, but the benefits to a utility such as the ability to shift load and firm renewable generation are obvious. Research, development, and demonstration continue within Duke Energy. Duke Energy Generation Services has installed a 36 MW advanced acid lead battery at the Notrees wind farm in Texas that began commercial operation in December 2012. In Indiana, Duke Energy has installed a 75 kW battery which is integrated with solar generation and electric vehicle charging stations. Duke Energy also has other storage system tests within its Envision Energy demonstration in Charlotte, which includes two Community Energy Storage (CES) systems of 24 kW, and three substation demonstrations less than 1 MW each.
- ***Compressed Air Energy Storage*** (CAES), although demonstrated on a utility scale and generally commercially available, is not a widely applied technology and remains relatively expensive. The high capital requirements for these resources arise from the fact that suitable sites that possess the proper geological formations and conditions necessary for the compressed air storage reservoir are relatively scarce.
- ***Small modular nuclear reactors*** (SMR) are generally defined as having capabilities of less than 300 MW. In 2012, U.S. Department of Energy (DOE) solicited bids for companies to participate in a small modular reactor grant program with the intent to "promote the accelerated commercialization of SMR technologies to help meet the nation's economic energy security and climate change objectives." The focus of the grant is the first-of-a-

kind engineering associated with NRC design certification and licensing efforts in order to demonstrate the ability to achieve NRC design certification and licensing to support SMR plant deployment on a domestic site by 2022. The grant was awarded to the Babcock & Wilcox Company, which will lead the effort in partnership with the Tennessee Valley Authority and the Bechtel Corporation. It is estimated that this project may lead to the development of "plug and play" type nuclear reactor applications that are about one-third the size of current reactors. These are expected to become commercially available around 2022. Duke Energy will be monitoring the progress of the SMR project for potential consideration and evaluation for future resource planning.

- ***Fuel cells***, although originally envisioned as being a competitor for combustion turbines and central power plants, are now targeted to mostly distributed power generation systems. The size of the distributed generation applications ranges from a few kW to tens of MW in the long-term. Cost and performance issues have generally limited their application to niche markets and/or subsidized installations. While a medium level of research and development continues, this technology is not commercially available for utility-scale application.
- ***Poultry and swine waste digesters*** remain relatively expensive and face operational and/or permitting challenges. Research, development, and demonstration continue, but these technologies remain generally too expensive or face obstacles that make them impractical energy choices outside of specific mandates calling for use of these technologies. Such projects are typically small and so would not materially impact the IRP.
- ***Off-shore wind***, although demonstrated on a utility scale and commercially available, is not a widely applied technology and not easily permitted. This technology remains expensive and has yet to actually be constructed anywhere in the United States. Currently, the Cape Wind project in Massachusetts has been approved with assistance from the federal government but has not begun construction.

Economic Screening

The Company screens all technologies using relative dollar per kilowatt-year ($/kW-yr) versus capacity factor. The screening within each general class uses a spreadsheet-based screening curve model developed by Duke Energy. The model is considered to be proprietary, confidential and competitive information by Duke Energy Indiana. The screening curve analysis model includes the total costs associated with owning and maintaining a technology type over its lifetime and computes a levelized \$/kW-year value over a range of capacity factors, using the same fuel prices for coal and natural gas, and NO_x, SO_2, and CO_2 allowance prices as in the Reference Scenario in the System Optimizer analysis (discussed in Chapter 8). This process is performed for each supply technology to create a family of lines. On the graph of all the lines in a general class, the lowest portions of the lines represent the least cost supply option at the corresponding capacity factor**.** Lines that are never lowest, or that are lowest only at capacity factors outside of their relevant operating ranges, have a very low probability of being part of the least cost solution, and can be eliminated from further analysis.

2. Screening Results

In the quantitative analysis phase, the Company further evaluates those technologies from each of the three general categories screened (Base load, Peaking/Intermediate, and Renewables), which had the lowest levelized busbar cost for a given capacity factor range within each of these categories. The results of the screening within each category are shown in Appendix A.

Even though EPA's MATS and GHG New Source regulations may effectively preclude new coal-fired generation, Duke Energy Indiana has included supercritical pulverized coal (SCPC) and IGCC technologies with CCS of 800 pounds/net-MWh as options for base load analysis consistent with the proposed EPA NSPS rules. Additional detail on the expected impacts from EPA regulations to new coal-fired options is included in Chapter 6.

Baseload Technologies

Figure A-1 in Appendix A shows the screening curves (both No CO_2 and with CO_2) for the following technologies in the baseload category:

1) 2 x 1,117MW Nuclear units (AP1000)
2) 825 MW Supercritical Pulverized Coal with and w/o CCS
3) 618 MW IGCC with and w/o CCS

Figure A-1 indicates that supercritical coal without CCS is the most cost effective baseload option; however, it would be difficult to permit new coal generation in the current regulatory environment. Nuclear generation is the next most cost effective baseload technology, followed by IGCC without CCS. Supercritical coal and IGCC with 90% CCS are the most costly as CCS costs are not competitive at current CO_2 allowance price projections.

Peak / Intermediate Technologies

Figure A-2 in Appendix A shows the screening curves (both No CO_2 and with CO_2) for the following technologies in the peak/intermediate category:

1) 174 MW 4-LM6000 CTs
2) 805 MW 4-7FA CTs
3) 843 MW – 2x2x1 Advanced Combined Cycle (Inlet Chiller and Fired)
4) 680 MW – 2x2x1 7FA CC (Inlet Chiller and Fired)
5) 1275 MW – 3x3x1 Advanced Combined Cycle (Inlet Chiller and Fired)

Figure A-2 indicates that simple-cycle CT generation is the best peaking option up to a 40% capacity factor in the No CO_2 case and up to 30% capacity factor in the case with CO_2. Combined Cycles with and without Duct Firing become the best option from 30-40% to 100% capacity factor.[10]

Renewable Technologies

Figure A-3 in Appendix A shows the screening curves for the following technologies in the renewable category:

1) 150 MW Wind – On-Shore
2) 25 MW Solar PV

One must remember that busbar chart comparisons involving some renewable resources, particularly wind and solar resources, can be somewhat misleading because these resources do

[10] Duct firing in a CC unit is a process to introduce more fuel (heat) directly into the combustion turbine exhaust (waste heat) stream, by way of a duct burner, to increase the temperature of the exhaust gases entering the Heat Recovery Steam Generator (HRSG). This additional heat allows the production of additional steam to produce more electricity in the steam (bottoming) cycle of a CC unit. It is a low cost ($/kW installed cost) way to increase power (MW) output during times of very high electrical demands and/or system emergencies. However, it adversely impacts the efficiency (raises the heat rate) and thereby increases the operating cost of a CC unit and is used primarily as a peaking resource.

not contribute their full installed capacity at the time of the system peak.[11] Since busbar charts attempt to levelize and compare costs on an installed kW basis, wind and solar resources appear to be more economic than they would be if the comparison was performed on a peak kW basis.

New hydro resources tend to be very site-specific; therefore, Duke Energy Indiana normally evaluates both pumped storage capacity and new run-of-river energy resources on a project-specific basis. Solar is the least expensive of the renewable options evaluated. It contributes more at the time of the summer peak than wind, but is limited to a 20% capacity factor on an annual basis. Wind is a close second to solar in cost-effectiveness, but is intermittent and does not contribute significantly to meeting the system peak.

Biomass generation is higher cost than wind but is a dispatchable resource and can compete as a baseload generation option. However, uncertainties associated with the lack of fuel infrastructure and the risk of biomass not being considered carbon neutral limit its use until there is more regulatory certainty. Even so, a nominal amount of biomass in the form of typical landfill gas was included in IRP modeling, although it was not shown on the screening curve.

3. <u>Unit Size</u>

The unit sizes selected for planning purposes generally are the largest technologies available today because they tend to offer lower $/kW installed capital costs due to economies of scale. However, the true test of whether a resource is economic depends on the economics of an overall resource plan that contains that resource (including fuel costs, operating and maintenance costs, emission costs, *etc.*), not merely on the installed $/kW cost. If a partial share of large unit sizes, such as those utilized for the Nuclear and/or IGCC technology types, are selected as part of a least cost plan, joint ownership can and may be pursued.

[11] For purposes of this IRP, wind resources are assumed to contribute 9% of installed capacity at the time of peak and solar resources are assumed to contribute 42% of installed capacity at the time of peak.

4. **<u>Cost, Availability, and Performance Uncertainty</u>**

Supply-side alternative project scope and estimated costs used for planning purposes for conventional technology types such as simple-cycle CT units and CC units are relatively well known based on our own building experience, cost estimates in the TAG®, information obtained from architect and engineering (A&E) firms, and equipment vendors. The current estimated CC cost uses the information obtained from the on-going combined cycle construction projects within Duke Energy. The cost estimates include step-up transformers and a substation to connect with the transmission system. Because any additional transmission costs would be site-specific and because specific sites requiring additional transmission are unknown at this time, typical values for additional transmission costs were added to the alternatives. The unit availability and performance of conventional supply-side options is also relatively well known and the TAG®, A&E firms and/or equipment vendors are sources of estimates of these parameters.

5. **<u>Lead Time for Construction</u>**

The estimated construction lead time and the lead time used for modeling purposes for the proposed simple-cycle CT units is three years. For the CC units, the estimated lead time is four years. For coal units, the lead time is five years. For nuclear units, the lead time is approximately eight years. However, the time required to obtain regulatory approvals and environmental permits adds uncertainty to the process and can increase the total project time by seven to eight years for nuclear units.

6. **<u>RD&D Efforts and Technology Advances</u>**

New energy and technology alternatives are needed to ensure a long-term sustainable electric future. Duke Energy's, development, and delivery (RD&D) activities enable Duke Energy Indiana to track new options including modular and potentially dispersed generation systems (small and medium nuclear reactors), CTs, and advanced fossil technologies. Emphasis is placed on providing information, assessment tools, validated technology, demonstration/deployment support, and RD&D investment opportunities for planning and implementing projects utilizing new power generation technology to assure the Company is in the forefront of electricity supply and delivery.

Of particular interest with regard to this resource plan is the expected advancements in CT/CC technology. Advances in stationary industrial CT/CC technology should result from ongoing research and development efforts to improve both commercial and military aircraft engine efficiency and power density, as well as expanding research efforts to burn more hydrogen-rich fuels. The ability to burn hydrogen-rich fuels will enable very high levels of CO_2 removal and shifting in the syngas utilized in IGCC technology, thereby enabling a major portion of the advancement necessary for a significant reduction in the carbon footprint of this coal-based technology.

7. <u>Coordination With Other Utilities</u>

Decisions concerning coordinating the construction and operation of new units with other utilities or entities are dependent on a number of factors including the size of the unit versus the capacity requirement of each utility and whether the timing of the need for facilities is the same. To the extent that units that are larger than needed for Duke Energy Indiana's requirements become economically viable in a plan, co-ownership can be considered at that time. Coordination with other utilities can also be achieved through purchases and sales in the bulk power market.

G. BENTON COUNTY WIND FARM PPA

Duke Energy Indiana has a 20-year power purchase agreement (PPA) with the Benton County Wind Farm. Duke Energy Indiana purchases the energy output from 100 MW of wind turbine capacity for a period of 20 years. This was the first commercial wind farm in the state of Indiana. The facility's in service date was April 19, 2008.

A capacity credit of 9% of the installed capacity was modeled (9 MW out of the installed 100 MW) as capacity toward the reserve margin requirement.

The Company only pays for the energy it receives from Benton County Wind at a fixed price per MWh, which escalates annually. Benton County Wind receives and retains existing and future tax credits or tax benefits as the owner or operator of the wind renewable energy project. Duke

Energy Indiana is entitled to ownership of all of the renewable energy certificates (RECs) and carbon credits associated with power produced by the wind turbines.

H. DUKE ENERGY INDIANA'S RENEWABLE ACTIVITIES

An extension of the Duke Energy Indiana GoGreen Power program was approved on July 3, 2013. The extension is for a three year term with the possibility of an automatic extension for an additional two-year period. The renewed program reduced the price for all green power kWh purchased per month from $2.00 per 100 kWh block to $1.00 per 100 kWh block, with a minimum purchase of two blocks. Duke Energy Indiana has committed to further reduce the block price to $0.90 in early 2014 if GoGreen revenues are sufficient. There are approximately 1375 customers on the program. Under the program, Duke Energy Indiana will purchase renewable energy in the form of renewable energy certificates. Duke Energy Indiana may self certify RECs created from new, renewable projects of 3 MW or less located within Duke Energy Indiana's service territory.

Due to a lack of participation, the Carbon Offset program was terminated as part of the IURC's July 3, 2013 order. The Carbon Offset participants were rolled into the GoGreen REC program.

I. WABASH RIVER 2-5

Analyses performed in the 2011 IRP and in Duke Energy Indiana's MATS rule Phase 2 Compliance Plan[12] showed that retirement of Wabash River units 2-5 was more economical than retrofitting these units to comply with MATS. The assumed retirement date in this IRP is the MATS compliance date of April 16, 2015.

J. EDWARDSPORT IGCC

The Edwardsport IGCC was declared in-service on June 7, 2013.

[12] Cause No. 44217.

Table 5-A
Duke Energy Indiana
Summary of Existing Electric Generating Facilities

Plant Name	Unit Number	City or County	State	In-Service Year	Unit Type	Primary Fuel	Secondary Fuel (if any)	Ownership %	Winter Rating (MW)	Summer Rating (MW)	Environmental Controls	Notes
Cayuga	1	Cayuga	IN	1970	ST	Coal		100.00%	505.0	500.0	FGD, EP, LNB, OFA, CT (SCR, DSI – 2014)	SCR and DSI under construction
Cayuga	2	Cayuga	IN	1972	ST	Coal		100.00%	500.0	495.0	FGD, EP, LNB, OFA, CT (SCR, DSI – 2015)	SCR and DSI under construction
Cayuga	3A	Cayuga	IN	1972	IC	Oil		100.00%	3.0	3.0	None	
Cayuga	3B	Cayuga	IN	1972	IC	Oil		100.00%	3.0	3.0	None	
Cayuga	3C	Cayuga	IN	1972	IC	Oil		100.00%	3.0	2.0	None	
Cayuga	3D	Cayuga	IN	1972	IC	Oil		100.00%	2.0	2.0	None	
Cayuga	4	Cayuga	IN	1993	CT	Gas	Oil	100.00%	120.0	99.0	DLN (Gas); WI (Oil)	
Connersville	1	Connersville	IN	1972	CT	Oil		100.00%	49.0	43.0	None	
Connersville	2	Connersville	IN	1972	CT	Oil		100.00%	49.0	43.0	None	
Edwardsport	IGCC	Knox County	IN	2013	IGCC	Syngas	Gas	100.00%	630.0	595.0	Selexol, SCR, MGB, CT	
Gallagher	2	New Albany	IN	1958	ST	Coal		100.00%	140.0	140.0	BH, LNB, OFA, DSI	DSI required by Consent Decree
Gallagher	4	New Albany	IN	1961	ST	Coal		100.00%	140.0	140.0	BH, LNB, OFA, DSI	DSI required by Consent Decree
Gibson	1	Owensville	IN	1976	ST	Coal		100.00%	635.0	630.0	FGD, SCR, SBS, EP, LNB, OFA, CL	
Gibson	2	Owensville	IN	1975	ST	Coal		100.00%	635.0	630.0	FGD, SCR, SBS, EP, LNB, OFA, CL	
Gibson	3	Owensville	IN	1978	ST	Coal		100.00%	635.0	630.0	FGD, SCR, SBS, EP, LNB, OFA, CL	
Gibson	4	Owensville	IN	1979	ST	Coal		100.00%	627.0	622.0	FGD, SCR, SBS, EP, LNB, OFA, CL	
Gibson	5	Owensville	IN	1982	ST	Coal		50.05%	312.8	310.3	FGD, SCR, SBS, EP, LNB, OFA, CL	Jointly owned with WVPA (25%) and IMPA (24.95%)
Henry County	1	Henry County	IN	2001	CT	Gas		100.00%	43.0	43.0	WI	50 MW from the plant is supplied to load other than DEI under PPA
Henry County	2	Henry County	IN	2001	CT	Gas		100.00%	43.0	43.0	WI	
Henry County	3	Henry County	IN	2001	CT	Gas		100.00%	43.0	43.0	WI	
Madison	1	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	2	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	3	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	4	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	5	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	6	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	7	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	8	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Markland	1	Florence	IN	1967	HY	Water		100.00%	15.0	15.0	None	
Markland	2	Florence	IN	1967	HY	Water		100.00%	15.0	15.0	None	
Markland	3	Florence	IN	1967	HY	Water		100.00%	15.0	15.0	None	

[1] Edwardsport IGCC capacity ratings are preliminary pending ongoing program performance testing. The summer capacity reflects evaporative coolers in service.

Table 5-A: Duke Energy Indiana
Summary of Existing Electric Generating Facilities

Plant Name	Unit Number	City or County	State	In-Service Year	Unit Type	Primary Fuel	Secondary Fuel (if any)	Ownership %	Winter Rating (MW)	Summer Rating (MW)	Environmental Controls	Notes
Miami-Wabash	1	Wabash	IN	1968	CT	Oil		100.00%	17.0	16.0	None	
Miami-Wabash	2	Wabash	IN	1968	CT	Oil		100.00%	17.0	16.0	None	
Miami-Wabash	3	Wabash	IN	1968	CT	Oil		100.00%	17.0	16.0	None	
Miami-Wabash	5	Wabash	IN	1969	CT	Oil		100.00%	17.0	16.0	None	
Miami-Wabash	6	Wabash	IN	1969	CT	Oil		100.00%	17.0	16.0	None	
Noblesville	1	Noblesville	IN	1950	ST in CC			100.00%	46.0	46.0	CT	Units 1 & 2 were repowered as Gas CC in 2003
Noblesville	2	Noblesville	IN	1950	ST in CC			100.00%	46.0	46.0	CT	Units 1 & 2 were repowered as Gas CC in 2003
Noblesville	3	Noblesville	IN	2003	CT in CC	Gas		100.00%	72.7	64.4	DLN, SCR, CO	CT and share of HRSG capacity combined
Noblesville	4	Noblesville	IN	2003	CT in CC	Gas		100.00%	72.7	64.4	DLN, SCR, CO	CT and share of HRSG capacity combined
Noblesville	5	Noblesville	IN	2003	CT in CC	Gas		100.00%	72.7	64.4	DLN, SCR, CO	CT and share of HRSG capacity combined
Vermillion	1	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	2	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	3	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	4	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	5	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	6	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	7	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	8	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Wabash River	2	West Terre Haute	IN	1953	ST	Coal		100.00%	85.0	85.0	EP, LNB, OFA	
Wabash River	3	West Terre Haute	IN	1954	ST	Coal		100.00%	85.0	85.0	EP, LNB, OFA	
Wabash River	4	West Terre Haute	IN	1955	ST	Coal		100.00%	85.0	85.0	EP, LNB, OFA	
Wabash River	5	West Terre Haute	IN	1956	ST	Coal		100.00%	95.0	95.0	EP, LNB, OFA	
Wabash River	6	West Terre Haute	IN	1968	ST	Coal		100.00%	318.0	318.0	EP, LNB, OFA	
Wabash River	7A	West Terre Haute	IN	1967	IC	Oil		100.00%	3.1	3.1	None	
Wabash River	7B	West Terre Haute	IN	1967	IC	Oil		100.00%	3.1	3.1	None	
Wabash River	7C	West Terre Haute	IN	1967	IC	Oil		100.00%	2.1	2.1	None	
Wheatland	1	Knox County	IN	2000	CT	Gas		100.00%	122.0	115.0	WI	
Wheatland	2	Knox County	IN	2000	CT	Gas		100.00%	122.0	115.0	WI	
Wheatland	3	Knox County	IN	2000	CT	Gas		100.00%	122.0	115.0	WI	
Wheatland	4	Knox County	IN	2000	CT	Gas		100.00%	122.0	115.0	WI	
Total									7,871.0	7,494.0		

Unit Type

ST	Steam
CT	Simple Cycle Combustion Turbine
CC	Combined Cycle Combustion Turbine
IC	Internal Combustion
HY	Hydro
IGCC	Integrated Coal Gasification Combined Cycle

Fuel Type

Coal
Gas
Syngas
Oil
Water

Environmental Controls

FGD	SO_2 Scrubber
SCR	Selective Catalytic Reduction
SBS	Sodium Bisulfite / Soda Ash Injection System
LNB	Low NO_x Burner
EP	Electrostatic Precipitator
BH	Baghouse
CT	Cooling Tower
CL	Cooling Lake
WI	Water Injection (NO_x)
OFA	Overfire Air
CO	Passive Carbon Monoxide Catalyst
DSI	Dry Sorbent Injection
MGB	Mercury Guard Carbon Bed
DLN	Dry Low NO_x Combustion System
Selexol	Acid-Gas removal technology

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6. ENVIRONMENTAL COMPLIANCE

A. INTRODUCTION

The purpose of the environmental compliance planning process is to develop an integrated resource/compliance plan that meets the future resource needs of Duke Energy Indiana while at the same time meeting environmental requirements in a reliable and economic manner. Compliance planning associated with existing laws and regulations is discussed in this chapter. Risks associated with anticipated and potential changes to environmental regulations are discussed in Section F.

B. CLEAN AIR ACT AMENDMENTS (CAAA) PHASE I COMPLIANCE

A detailed description of Duke Energy Indiana's CAAA Phase I compliance planning process can be found in the 1995, 1997, and 1999 IRPs.

C. CAAA PHASE II COMPLIANCE

A detailed description of Duke Energy Indiana's CAAA Phase II compliance planning process can be found in the 1995, 1997, and 1999 IRPs.

D. NO_x STATE IMPLEMENTATION PLAN CALL COMPLIANCE

A detailed description of Duke Energy Indiana's Nitrogen Oxide ($NO_{x)}$ State Implementation Plan (SIP) Call compliance planning process can be found in the 1999, 2001, and 2003 IRPs.

E. CLEAN AIR INTERSTATE RULE (CAIR) AND CLEAN AIR MERCURY RULE (CAMR) - DUKE ENERGY INDIANA PHASE 1

A detailed description of Duke Energy Indiana's CAIR and CAMR Phase 1 compliance planning process and results can be found in the 2005, and 2007, and 2009 IRPs.

F. ENVIRONMENTAL RISK/REGULATORY IMPACTS

There are a number of environmental risks/regulatory changes that can affect Duke Energy Indiana in the future. As a result, Duke Energy Indiana closely monitors these changes and develops responses to the changes. The most significant risks are discussed in more detail below.

1. **Ozone National Ambient Air Quality Standards (NAAQS)**

In 1997, the United States Environmental Protection Agency (US EPA or EPA) announced a new and tighter 8-hour ozone standard of 84 parts per billion (ppb) to protect human health. The standard established new limits for the permissible levels of ground level ozone in the atmosphere. However, the effect of the standard and its implementation were delayed for years in court proceedings, as the standard was challenged, but ultimately upheld. Still, the Circuit Court for the District of Columbia invalidated the EPA's implementation procedure for dealing with the 8-hour ozone standard.

In March 2008, EPA revised the 8 Hour Ozone Standard by lowering it from 84 to 75 ppb. In September of 2009, EPA announced a decision to reconsider the 75 ppb standard in response to a court challenge from environmental groups and its own belief that a lower standard was justified. However, EPA announced in September 2011 that it would retain the 75 ppb primary standard until it is reconsidered under the next 5-year review cycle. The schedule for EPA to complete its ongoing review of the 75 ppb standard is uncertain.

On May 21, 2012, EPA finalized the area designations for the 2008 75 ppb 8-hour ozone standard. There are no nonattainment areas in Duke Energy Indiana's service territory.

2. **Particulate Matter NAAQS ($PM_{2.5}$)**

In 1997, EPA announced new annual and daily particulate matter (PM) standards intended to protect human health. The standards establish limits for very small particulate, those considered respirable, less than 2.5 microns in diameter. The control of these very small particles could require significant reductions in gaseous SO_2 and NO_x emissions. As with the ozone standard discussed above, EPA's new PM standard and subsequent implementation were delayed for years because of legal challenges.

In September 2006, the EPA announced its decision to revise the $PM_{2.5}$ NAAQS standard. The daily standard was reduced from 65 ug/m^3 (micrograms per cubic meter) to 35 ug/m^3. The annual standard remained at 15 ug/m^3.

EPA finalized designations for the 2006 daily standard in October 2009, which did not include any nonattainment areas in the Duke Energy Indiana service territory. In February 2009, the D.C Circuit unanimously remanded to EPA the Agency's decision to retain the annual 15 ug/m^3 primary $PM_{2.5}$ NAAQS and to equate the secondary $PM_{2.5}$ NAAQS with the primary NAAQS. EPA began undertaking new rulemaking to revise the standards consistent with the Court's decision.

On December 14, 2012, the EPA finalized a rule that lowered the annual $PM_{2.5}$ standard to 12 ug/m^3 and retained the 35 ug/m^3 daily $PM_{2.5}$ standard. The EPA plans to finalize area designations by December 2014. States with nonattainment areas will be required to submit SIPs to EPA in early 2018, with the initial attainment date in 2020. The EPA has indicated that it will likely use 2011 – 2013 air quality data to make final designations.

To date, neither the annual nor the daily $PM_{2.5}$ standard has directly driven emission reduction requirements at Duke Energy Indiana facilities. The reduction in SO_2 and NO_x emissions to address the $PM_{2.5}$ standards has been achieved through CAIR compliance. It is unclear if the new lower annual $PM_{2.5}$ standard will require additional SO_2 or NO_x emission reduction requirements at any Duke Energy Indiana generating facilities.

3. <u>SO_2 NAAQS</u>

On June 22, 2010 EPA established a 75 ppb 1-hour SO_2 NAAQS and revoked the annual and 24-hour SO_2 standards. EPA finalized initial nonattainment area designations in July 2013. The area around Wabash River was designated nonattainment. The state is required to develop a plan to bring the area into attainment within 5 years of the effective date of the designation. Wabash River units 2-5 will potentially be retired by April 2015 in response to the EPA's MATS rule, and Wabash Rive unit 6 will potentially be fuel switched to natural gas. If this does not occur, the state attainment plan will need to address the emissions from these units.

On February 6, 2013, the EPA released a document that updated its strategy for addressing all areas it did not initially designate as nonattainment in July 2013. The document indicated that EPA will allow states to use modeling or monitoring to evaluate the impact of large SO_2

emitting sources relative to the 75 ppb standard. The document also laid out a schedule for implementing the standard.

The EPA plans on undertaking notice and comment rulemaking to codify the implementation requirements for the 75 ppb standard. There is no schedule for EPA to propose or finalize the rulemaking, and the outcome of the rulemaking could be different from what EPA put forth in its February 6, 2013 document.

4. <u>Cross-State Air Pollution Rule – Replacement for Clean Air Interstate Rule (CAIR)</u>

The EPA finalized its Clean Air Interstate Rule (CAIR) in May 2005. The CAIR limits total annual and summertime NO_x emissions and annual SO_2 emissions from electric generating facilities across the Eastern U.S. through a two-phased cap-and-trade program. In December 2008, the United States District Court for the District of Columbia issued a decision remanding CAIR to the EPA, allowing CAIR to remain in effect until EPA developed a replacement regulation.

In August 2011, a replacement for CAIR was finalized as the Cross-State Air Pollution Rule (CSAPR); however, on December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the D.C. Circuit. Numerous petitions for review of CSAPR were filed with the D.C. Circuit Court. On August 21, 2012, by a 2-1 decision, the D.C. Circuit vacated CSAPR. The Court also directed the EPA to continue administering CAIR pending completion of a remand rulemaking to replace CSAPR with a valid rule. CAIR requires additional Phase II reductions in SO_2 and NO_x emissions beginning in 2015. The court's decision to vacate the CSAPR leaves the future of the rule uncertain. The EPA filed a petition with the D.C. Circuit for en banc rehearing of the CSAPR decision, which the court denied. EPA then filed a petition with the Supreme Court asking that it review the D.C. Circuit's decision. On June 24, 2013, the Supreme Court granted EPA's petition. The Court will review the three issues presented in EPA's petition. Barring unforeseen developments, the Court could issue its decision by June 2014. The Supreme Court's order granting review does not change the legal status of CSAPR, *i.e.*, CSAPR does not have legal effect at this time, and EPA is required to continue to administer the CAIR.

Duke Energy Indiana cannot predict the outcome of the review process or how it could affect future emission reduction requirements that might apply as a result of a potential CSAPR replacement rulemaking. If the Supreme Court affirms the D.C. Circuit's decision on all issues, it is likely to take beyond 2015 for a replacement rulemaking to become effective, which means that Phase II of CAIR would take effect on January 1, 2015. Duke Energy Indiana can already comply with CAIR Phase I and II and CSAPR Phase I and II, so no additional controls are planned for these regulations. If the review process results in the CSAPR being reinstated, it is unclear when EPA might move to implement the rule.

5. Mercury and Air Toxics Standard (MATS)

The Indiana Department of Environmental Management (IDEM) adopted the EPA version of the CAMR in October 2007. Numerous states, environmental organizations, industry groups and individual companies challenged various portions of the CAMR, including the determination that it is not appropriate or necessary to regulate mercury emissions under Section 112 of the Clean Air Act and the utilization of a cap-and-trade mechanism for mercury reductions. The Appeals Court of the D.C. Circuit vacated the entire rule in February 2008 due to numerous significant flaws. This action had the effect of eliminating all of the associated regulations requiring control and monitoring of mercury emissions until EPA could complete further rulemaking.

EPA announced a proposed Utility Boiler Maximum Achievable Control Technology (MACT) rule in March 2011 to replace the CAMR. The EPA published the final rule, known as the Mercury and Air Toxics Standard (MATS), in the Federal Register on February 16, 2012. MATS regulates Hazardous Air Pollutants (HAPs) and establishes unit-level emission limits for mercury, acid gases, and non-mercury metals, and sets work practice standards for organics for coal and oil-fired electric generating units. Compliance with the emission limits will be required by April 16, 2015. Permitting authorities have the discretion to grant up to a 1-year compliance extension, on a case-by-case basis, to sources that are unable to install emission controls before the compliance deadline.

Numerous petitions for review of the final MATS rule have been filed with the United States Court of Appeals for the District of Columbia. Briefing in the case has been completed. Oral arguments have not been scheduled. A court decision in the case is not likely until the first half of 2014. Duke Energy Indiana cannot predict the outcome of the litigation or how it might affect the MATS requirements as they apply to operations.

Based on the emission limits established by the MATS rule, compliance with the MATS rule will drive the retirement or fuel conversion of several non-scrubbed coal-fired generating units in Indiana.

6. Clean Water Act Section 316(a) and 316(b)

Protection of single fish species and aquatic communities is a primary focus of water permitting for coal, oil, gas, and nuclear power plants and industrial facilities under the Clean Water Act Section 316(a) - heated cooling water discharges, and 316(b) – entrainment through cooling water intake systems and impingement on intake screens

All of Duke Energy Indiana's existing stations that have once-through cooling are potentially affected by Section 316(a) regulation of a station's heated cooling-water discharge: however, we do not see a significant likelihood that cooling towers would be required at any of those stations to comply with the Section 316(a) requirements.

Federal regulations implementing Section 316(b) of the Clean Water Act may necessitate cooling water system modifications for existing facilities to minimize impingement and entrainment of aquatic organisms. EPA published its proposed rule on April 20, 2011.

The proposed rule establishes mortality reduction requirements due to both fish impingement and entrainment and advances one preferred approach and three alternatives. The EPA's preferred approach establishes aquatic protection requirements for existing facilities and new on-site generation that are defined as existing facilities with a design intake flow of 2 million gallons per day (mgd) or more from waters of the U.S. utilize at least 25% of the water withdrawn for cooling purposes and is defined as a point source under the Clean Water Act. The installation of cooling towers was not specified as presumptive Best Technology Available (BTA) for entrainment in the proposed rule. Site specific evaluations, however, to determine BTA to address entrainment are required to be conducted and closed-cycle cooling and fine mesh screens must be evaluated. Duke Energy has not observed significant impacts to the aquatic communities due to the operation of the cooling water intakes at the Indiana stations. It is, therefore, unlikely that cooling towers would be warranted. If the rule is finalized as proposed, the environmental impacts from the operation of the cooling water intakes will be further evaluated. The need for the installation of entrainment protective technologies, such as cooling towers, will be assessed at that time.

The most recent EPA settlement agreement now calls for the EPA to finalize the 316(b) rule by November 4, 2013. If the rule is finalized as proposed, initial submittals, station details, study plans, *etc*., for some facilities would be due in mid to late 2014. If required, modifications to the intakes to comply with the impingement requirements could be required as early as late 2017. Within the proposed rule, EPA did not provide a compliance deadline for meeting the entrainment requirements.

7. **Steam Electric Effluent Limitation Guidelines**

In September 2009, EPA announced plans to revise the steam electric effluent limitation guidelines. The steam electric effluent limitation guidelines are technology-based, in that limits are based on the capability of the best technology available. On April 19, 2013, the EPA Acting Administrator signed the proposed revisions to the Steam Electric Effluent Limitations Guidelines (ELGs). The proposal was published in the Federal Register on June 7, 2013, with comments due to EPA by the extended date of September 20, 2013. Duke Energy filed its comments on the proposed rule on September 19, 2013. Under the current revision of the consent decree, the EPA has agreed to issue a final rule by May 22, 2014. The EPA has proposed eight different regulatory options within the rule, of which four are listed as preferred by EPA. The eight regulatory options vary in stringency and cost, and propose revisions or development of new standards for seven waste streams, including wastewater from air pollution control equipment and ash transport water. The proposed revisions are focused primarily on coal generating units, but some revisions would be applicable to all steam electric generating units, including natural gas and nuclear-fueled generating facilities. After the final rulemaking, effluent limitation guideline requirements will be included in a station's National Pollutant Discharge Elimination System (NPDES) permit renewals. Portions of the rule would be implemented immediately after the effective date of the rule upon the renewal of wastewater discharge permits, while other portions of the rule will be implemented upon the renewal of the wastewater discharge permits after July 2017. EPA expects that all facilities will be in compliance with the rule by July 2022. The deadline to comply will depend upon each station's permit renewal schedule.

8. <u>Coal Combustion Residuals (CCR)</u>

In April 2000, EPA issued a regulatory determination for fossil fuel combustion wastes (65 FR 32214, May 22, 2000). The purpose of the determination was to decide whether certain wastes from the combustion of fossil fuels should remain exempt from subtitle C (management as hazardous waste) under the Resource Conservation and Recovery Act (RCRA). The Agency's decision was to retain the exemption from hazardous waste management for all of the fossil fuel combustion wastes. However, the Agency also determined and announced that waste management regulations under RCRA subtitle D (management as non-hazardous wastes) are appropriate for certain coal combustion wastes that are disposed in landfills and surface impoundments.

Following Tennessee Valley Authority's Kingston ash dike failure in December 2008, EPA began an effort to assess the integrity of ash dikes nationwide and to begin developing a rule to manage CCRs. CCRs include fly ash, bottom ash and FGD byproducts (including gypsum). Since the 2008 dike failure, numerous ash dike inspections have been completed by EPA and an enormous amount of input has been received by EPA as it developed proposed regulations.

In June 2010, EPA issued its proposed rule regarding CCRs. The proposed rule offers two options: 1) a hazardous waste classification under Resource Conservation and Recovery Act (RCRA) Subtitle C and 2) a non-hazardous waste classification under RCRA Subtitle D, along with dam safety and alternative rules. Both options would include strict new requirements regarding the handling, disposal and potential re-use ability of CCRs. The proposal could result in more conversions to dry handling of ash, more landfills, closures of existing ash ponds and the addition of new wastewater treatment systems. Final regulations are not expected to be issued by EPA until 2014 or later. EPA's regulatory classification of CCRs as hazardous or non-hazardous will be critical in developing plans for handling CCRs. However, under either option of the proposed rule, the impact to Duke Energy Indiana is likely to be significant. Based on a 2014 final rule date, compliance with new regulations is generally expected to begin around 2019.

9. <u>Greenhouse Gas Regulation</u>

The EPA has been active in the regulation of greenhouse gases (GHGs). In May 2010, the EPA finalized what is commonly referred to as the Tailoring Rule. This rule sets the emission thresholds to 75,000 tons/year of CO_2 for determining when a modified major stationary source is subject to Prevention of Significant Deterioration (PSD) permitting for greenhouse gases. The Tailoring Rule went into effect beginning January 2, 2011. Being subject to PSD permitting requirements for CO_2 will require a Best Available Control Technology (BACT) analysis and the application of BACT for GHGs. BACT will be determined by the state permitting authority. Since it is not known if, or when, a Duke Energy Indiana generating unit might undertake a modification that triggers PSD permitting requirements for GHGs and exactly what might constitute BACT, the potential implications of this regulatory requirement are unknown. The Supreme Court has agreed to review the D.C. Circuit's decision in the Tailoring Rule litigation. The Court's review will address whether EPA can regulate greenhouse gases under the PSD program.

On September 20, 2013, EPA proposed a rule to establish GHG new source performance standards (NSPS) for new electric utility steam generating units (EGUs). The proposed GHG NSPS applies to new pulverized coal (PC), integrated gasification combined cycle (IGCC) and natural gas combined cycle (NGCC) units. The proposed emissions limits for new NGCC units are 1,000 to 1,100 lb CO_2/gross MWh of electricity generation depending on unit size. The proposed emissions limits for new PC and IGCC units are also 1,000 to 1,100 lb CO_2/gross MWh depending on the compliance averaging period used. The only way a new PC or IGCC unit could meet the proposed standard is with carbon capture and storage technology.

On June 25, 2013, the President directed EPA to propose CO_2 emission guidelines for existing electric generating units by June 1, 2014, and finalize guidelines by June 1, 2015. Once EPA finalizes emission guidelines for existing sources, the states will be required to develop the regulations that will apply to covered sources, based on the emission performance standards established by EPA in its guidelines. EPA was also directed by the President to require states to submit their plans to EPA for approval by June 30, 2016. The requirements of this rulemaking are not known.

It is highly unlikely that legislation mandating reductions in GHG emissions or establishing a carbon tax will be passed by the 113th Congress, which began on January 3, 2013. Beyond 2014, the prospects for enactment of any federal legislation mandating reductions in GHG emissions or establishing a carbon tax are highly uncertain.

Duke Energy Indiana currently includes a range of CO_2 prices in the scenarios and sensitivities it evaluates. Our current range of prices includes the Low Regulation Scenario with a CO_2 emissions price of $0/ton throughout our planning period, and the Environmental Focus Scenario with up to $75/ton, and a related sensitivity case with up to $100/ton. We believe our current range of prices, including a zero price, is appropriate given the outcome of past debates over federal climate change legislation, the significant uncertainty surrounding the future direction of U.S. climate change policy, and our belief that to be potentially politically acceptable, climate change policy would need to be moderate. If or when there is clarity around future U.S. legislative or regulatory climate change policy, Duke Energy Indiana will adjust its CO_2 price forecasts as needed to reflect that clarity.

G. ENVIRONMENTAL COMPLIANCE PLAN

The Duke Energy Indiana MATS rule Phase 2 Compliance Plan[13] resulted in the recommendation of, and approval by the IURC of, the following emission control equipment and strategic components: (1) the installation of SCRs with SO_3 mitigation on Cayuga Units 1 and 2; (2) the installation of mercury re-emission chemical additive systems to the existing scrubbers on Cayuga Units 1 and 2, Gibson Units 1-3, and Gibson Unit 5; (3) the installation of mercury trim controls,

[13] Cause No. 44217.

specifically activated carbon injection, on Cayuga Units 1 and 2, and Gibson Unit 5; and (4) the retirement of Wabash River Units 2-5 by the MATS compliance date. These emission controls were identified as part of an overall optimal plan to comply with the Utility MATS rule. Duke Energy Indiana has continued to evaluate mercury reduction technology options as discussed further, resulting in some adjustments that will be proposed to the Phase 2 Plan. The construction of the Cayuga SCRs is in progress; construction of the other smaller components of the Phase 2 Plan will commence by early 2014.

With the core aspects of Duke Energy Indiana's MATS rule Phase 2 compliance plan established, further analysis was undertaken to determine and fine-tune the balance of the MATS compliance plan (*i.e.*, the Phase 3 Plan). In addition to the MATS rule, the environmental compliance planning process incorporates potential costs and requirements of other pending or proposed EPA regulations. Reference Scenario modeling assumptions were generally based on the best available information from any proposed rules. The Low Regulation and Environmental Focus Scenarios, as well as the high and low sensitivities for each scenario were developed based on potential ranges in the outcomes of the proposed rules, if any such guidance was available. Where no guidance was available, reasonable assumptions were made to develop a range for planning purposes only.

Besides the MATS rule, which is a final rule, and except carbon assumptions which are discussed elsewhere, the suite of environmental regulations and general requirements modeled included:

- CCR Rule, and ELG revisions
  - Dry ash management conversion costs
  - Waste water treatment addition/upgrade costs
  - Landfill construction costs
- 316(b) Intake Structure Rule
  - Aquatic impingement and entrainment studies
  - Intake structure and traveling screen upgrade costs
  - Cooling tower installations were assumed to be mandated for coastal and estuarial units in the Environmental Focus Scenario and Reference Scenario high sensitivity, but this assumption only impacted the development of fundamental forecast inputs as none of Duke Energy Indiana's assets meet these criteria

- Also for fundamental forecast development purposes only, the compliance timeframe for 316(b) ranged from 2020 in the Low Regulation Scenario base case and Reference Scenario low sensitivity, to as early as 2016 in the Reference Scenario base case and Environmental Focus Scenario. This range did not impact the units' specific IRP modeling as the compliance timeframes were based off of each facility's NPDES permit renewal schedule per the proposed rule.

- National Ambient Air Quality Standards (NAAQS) for Ozone and SO_2
  - Increased risk for additional NO_x and SO_2 reductions
  - Increased risk for site-specific control requirements
  - Given that Cayuga and Gibson will be fully scrubbed with SCR, and that the Wabash River Station units will either be retired or converted to natural gas firing, the NAAQS assumptions mainly impacted future modeling of Gallagher, which was either required to install SNCR (all scenarios/sensitivities except the Reference Scenario high sensitivity and Environmental Focus Scenario base case and high sensitivity) or assumed to retire due to a requirement to install SCR and/or FGD. Except in the Low Regulation Scenario, Cayuga and Gibson were assumed to install relatively low cost scrubber additives for enhanced SO_2 control, and Gibson units were modeled with SCR upgrades for increased NO_x removal, all in the 2020 timeframe.

Little more is known at this time about these pending or proposed rules than was known during the development of the 2011 IRP, as the finalization of these rules has generally continued to be delayed. The balance of all of the assumptions for the compliance analysis were reviewed and updated where necessary to coincide with the other assumptions used for the development of this IRP.

1. Compliance Planning Process

For this analysis, Duke Energy Indiana generally utilized the same three-stage analytical modeling process as in other past compliance planning activities, involving an external vendor's (for 2013, EVA) national modeling tools and Duke Energy Indiana's internal Engineering Screening Model. This most recent Phase 3 analysis concentrated on fine tuning the MATS compliance plan mercury trim control selections, as well as on specific control versus retirement analysis for Wabash River Unit 6.

EVA used their national modeling tools to model the current MATS rule, as well as other pending or proposed rules. As in the past, from these modeling runs Duke Energy Indiana was provided forecasted emission allowance prices, power prices, and fuel prices. EVA provided the fundamental forecast information for the Reference Scenario, as well as the Low Regulation and Environmental Focus Scenarios.

2. Engineering Screening Model

Historically, Duke Energy Indiana's in-house Engineering Environmental Compliance Planning and Screening Model (Engineering Screening Model) has been used to screen down a large number of air-emission control alternatives to the most economic emission reduction options. As some generating units have already been committed to retirement and others are already well controlled or undergoing construction of additional controls, the number of remaining viable air-emission control alternatives has dwindled. As a result, no specific screening activity was performed for the Phase 3 planning analysis using the Engineering Screening Model. However, the model's functionality was still used to organize modeling information, and provide the necessary modeling characteristic data for emission control alternatives to the System Optimizer and Planning and Risk models (discussed in Chapter 8).

The Engineering Screening Model incorporates the operating characteristics of the Duke Energy Indiana units (net MW, heat rates, emission rates, emission control equipment removal rates, availabilities, variable operating and maintenance expenses, etc.), and market information (energy, emission allowance, and fuel prices), calculates the dispatch costs of the units, and dispatches them independently against the energy price curve. The model calculates generation, emissions, operating margin, and, ultimately, free cash flow with the inclusion of capital costs.

The Engineering Screening Model also contains costs and operating characteristics of emission control equipment. This includes wet and dry flue gas desulfurization equipment (FGD or scrubber) and dry sorbent injection for SO2 removal; selective and non-selective catalytic reduction (SCR and SNCR) and low NOx burners (LNB) for NOx removal; baghouses, activated carbon injection (ACI), mercury re-emission chemical, and calcium bromide fuel additive for mercury removal; and various fuel switching options with related capital costs (such as a switch to lower sulfur content coal with required electrostatic precipitator upgrades). The model also appropriately treats emission reduction co-benefits, such as increased mercury removal with the combination of SCR and FGD. The Engineering Screening Model was used to support this IRP by organizing modeling information and providing the necessary modeling characteristic data for emission control alternatives to the System Optimizer and Planning and Risk models. The model is considered proprietary confidential and competitive information by Duke Energy Indiana.

New Technologies

Investigating new emission control technologies was discussed in the 2005, 2007, and 2009 IRPs. Duke Energy Indiana continues to investigate alternative emission control options that may be operationally, environmentally, and/or economically more advantageous than traditional or demonstrated technologies. Recently, the most promising options include relatively low cost chemical additives that may enhance the ability of existing controls to remove some pollutants, such as mercury. Duke Energy Indiana has continued testing some of these technologies, and has incorporated them into its Phase 2 and Phase 3 compliance plans based on positive results achieved. In addition, Duke Energy Indiana is also pursuing the possible conversion of existing coal-fired boilers to natural gas firing as a means of retaining the capacity value of a unit while achieving significant emission reductions.

Capital Cost Estimates

Phase 3 Plan capital cost estimates were generally developed based on actual ongoing vendor contract negotiations for project installation (Gibson precipitator refurbishments), preliminary engineering study results (Wabash River Unit 6 gas conversion), or actual installations at other Duke Energy Indiana units (PM CEMS, mercury sorbent traps, *etc*.). High-level cost estimates have also been developed for other compliance requirements, such as dry ash management conversion, wastewater treatment, and the other such projects noted above. For units and project options that have not had detailed studies performed, costs have been estimated using best engineering judgment of equipment and installation requirements, typically based on industry information. This includes reviewing technological aspects, trends in the cost of construction, and construction retrofit difficulty. To the extent that a majority of the costs included in the analysis are represented for compliance requirements for regulations that are not yet final, establishing a sensitivity range for the cost estimates has little validity. There is likely more error in the selection of the assumed compliance project than in the cost estimate for the project assumed. Therefore, just to establish a cost estimate range for modeling purposes, a low sensitivity of -5% was conservatively used, and a high sensitivity of +20% was used.

Technology Options

The primary air emission control technologies evaluated in the analysis include a newly tested calcium bromide fuel additive for mercury oxidation, as well as the refurbishment of some existing older emission control equipment on some units (due to positive outcomes of some final regulations, and the elimination of the need to consider replacement of those controls) In addition, costs were considered for the balance of Phase 3 Plan requirements, including MATS emission monitoring costs. Lastly, an assessment of converting Wabash River Unit 6 to natural gas firing was performed. An overview of the core air emission control technologies included in the IRP analysis is shown in Table 6-A below.

Table 6-A

Air Pollution Control Technologies included in the Analysis	
Gibson Units 1-2	Calcium bromide fuel additive
Gibson Unit 3	Calcium bromide fuel additive; precipitator refurbishment
Gibson Unit 4	Calcium bromide fuel additive; precipitator refurbishment
Gibson Unit 5	Calcium bromide fuel additive
	Precipitator refurbishment, multiple scopes
	FGD refurbishment, multiple scopes
	FGD replacement
Wabash River Unit 6	Natural gas conversion

In addition to these specific air emission control project options, as needed and where appropriate, cost assumptions were also included for other pending air, waste and water regulations' compliance requirements so as to address all of these regulations simultaneously.

3. System Optimizer / Planning and Risk Results

The Phase 3 Plan air-emission control alternatives associated with Wabash River and Gibson passed to the System Optimizer and Planning and Risk models from the Engineering Screening Model were analyzed in the integration step of this IRP in conjunction with the energy efficiency and supply-side alternatives. This is discussed in detail in Chapter 8.

While the general results from these Phase 3 analyses are likely indicative of the direction needed to comply with the MATS rule and the other pending regulations, it should be noted that most of these requirements are not yet finalized. As a result, Duke Energy Indiana's analyses and planning to meet these rule requirements, as well as any additional environmental requirements, (including any potential for additional unit retirements) will generally be an ongoing effort until such time as compliance with future requirements is achieved.

H. EMISSION ALLOWANCE MANAGEMENT

Figure 6-A shows the base number of SO_2 allowances allotted by the US EPA for affected units on the Duke Energy Indiana system for the Title IV Acid Rain program, and equivalent for the CAIR 2014 and 2015 and forward control periods. Figures 6-B and 6-C show the base number of Seasonal and Annual NO_x allowances, respectively, allotted by the US EPA for affected units on the Duke Energy Indiana system for the CAIR 2014 and 2015 and forward control periods.

The emission allowance markets can impact compliance strategies. The projected allowance market price is a basis against which the costs of compliance options are compared to determine whether the options are economic (*i.e.*, a "market-based" compliance planning process). Recently, with the vacatur of the CSAPR and the significant additional emission reductions expected to be achieved in the industry due to the MATS rule through new control installations and unit retirements, forward projected emission allowance prices for SO_2 and NO_x are very low, typically below the variable cost of control. Therefore, these markets are not playing a significant role in the environmental compliance strategy at this time.

Duke Energy Indiana has maintained an interdepartmental group to perform SO_2 and NO_x emission allowance management. Duke Energy Indiana manages emissions risk by utilizing a mixture of purchasing or selling allowances, installing equipment and, when applicable, purchasing power. The most economic decision is dependent upon the current and forecasted market price of allowances, the cost and lead-time to install control equipment, and the current and forecasted market price of power. These factors will be reviewed as the markets change and the most economic emission compliance strategy will be employed.

Figure 6-A

SO_2 ALLOWANCES ALLOCATED TO DUKE ENERGY INDIANA UNITS

(Tons)

			BASE ALLOWANCES ALLOCATED		
Plant Name	Unit/ Boiler No.	Percent Ownership	Title IV, 2010 & after	CAIR*, 2014	CAIR*, 2015 & after
Cayuga	1	100.00	14,415	14,415	14,415
Cayuga	2	100.00	14,740	14,740	14,740
Cayuga	4	100.00	0	0	0
Edwardsport	6-1	100.00	0	0	0
Edwardsport	7-1	100.00	348	348	348
Edwardsport	7-2	100.00	355	355	355
Edwardsport	8-1	100.00	375	375	375
Gallagher	1	100.00	2,914	2,914	2,914
Gallagher	2	100.00	3,144	3,144	3,144
Gallagher	3	100.00	2,821	2,821	2,821
Gallagher	4	100.00	2,938	2,938	2,938
Gibson	1	100.00	17,449	17,449	17,449
Gibson	2	100.00	17,713	17,713	17,713
Gibson	3	100.00	17,743	17,743	17,743
Gibson	4	100.00	17,419	17,419	17,419
Gibson	5	50.05	9,117	9,117	9,117
Noblesville Repowering**	1-5	100.00	160	160	160
Wabash River	1	100.00	1,726	1,726	1,726
Wabash River	2	100.00	1,394	1,394	1,394
Wabash River	3	100.00	1,619	1,619	1,619
Wabash River	4	100.00	1,534	1,534	1,534
Wabash River	5	100.00	1,584	1,584	1,584
Wabash River	6	100.00	5,304	5,304	5,304
Total Duke Energy Indiana owned units			134,812	134,812	134,812

Note: Number of allowances shown are Duke Energy Indiana's portion for Gibson 5.

*CAIR - Clean Air Interstate Rule

Allowance surrender ratio in 2014 is 2.0 allowances per ton of emission

Allowance surrender ratio in 2015 and after is 2.86 allowances per ton of emission

**Title IV allocations for Noblesville Repowering include holdover allocations from retired boilers 1-3

Figure 6-B

SEASONAL NO_x ALLOWANCES ALLOCATED TO DUKE ENERGY INDIANA UNITS

(Tons)

Plant Name	Unit/ Boiler No.	Percent Ownership	BASE ALLOWANCES ALLOCATED CAIR*, 2014	CAIR*, 2015 & after
Cayuga	1	100.00	1,061	TBD
Cayuga	2	100.00	1,043	TBD
Cayuga	4	100.00	11	TBD
Connersville	1	100.00	2	TBD
Connersville	2	100.00	2	TBD
Edwardsport	6-1	100.00	6	TBD
Edwardsport	7-1	100.00	99	TBD
Edwardsport	7-2	100.00	90	TBD
Edwardsport	8-1	100.00	89	TBD
Gallagher	1	100.00	255	TBD
Gallagher	2	100.00	264	TBD
Gallagher	3	100.00	293	TBD
Gallagher	4	100.00	275	TBD
Gibson	1	100.00	1,387	TBD
Gibson	2	100.00	1,283	TBD
Gibson	3	100.00	1,368	TBD
Gibson	4	100.00	1,424	TBD
Gibson	5	50.05	658	TBD
Henry County	1	100.00	11	TBD
Henry County	2	100.00	11	TBD
Henry County	3	100.00	11	TBD
Madison	1	100.00	9	TBD
Madison	2	100.00	8	TBD
Madison	3	100.00	9	TBD
Madison	4	100.00	8	TBD
Madison	5	100.00	8	TBD
Madison	6	100.00	8	TBD
Madison	7	100.00	8	TBD
Madison	8	100.00	7	TBD
Noblesville Repowering**	1-5	100.00	274	TBD
Vermillion	1	62.50	3	TBD
Vermillion	2	62.50	3	TBD
Vermillion	3	62.50	3	TBD
Vermillion	4	62.50	3	TBD
Vermillion	5	62.50	3	TBD
Vermillion	6	62.50	3	TBD
Vermillion	7	62.50	3	TBD
Vermillion	8	62.50	3	TBD
Wabash River	2	100.00	171	TBD
Wabash River	3	100.00	179	TBD
Wabash River	4	100.00	195	TBD
Wabash River	5	100.00	204	TBD
Wabash River	6	100.00	670	TBD
Wheatland	1	100.00	11	TBD
Wheatland	2	100.00	12	TBD
Wheatland	3	100.00	12	TBD
Wheatland	4	100.00	13	TBD
Total Duke Energy Indiana owned units			11,472	

Notes

Number of allowances shown are Duke Energy Indiana's portion for Gibson 5 and Vermillion, rounded.

*CAIR - Clean Air Interstate Rule

The State of Indiana has not yet determined CAIR allocations for 2015 and forward

2015 and forward allocations are expected to be lower than 2014 allocations

**CAIR allocations for Noblesville Repowering include holdover allocations from retired boilers 1-3.

Figure 6-C

ANNUAL NO_x ALLOWANCES ALLOCATED TO DUKE ENERGY INDIANA UNITS

(Tons)

Plant Name	Unit/ Boiler No.	Percent Ownership	BASE ALLOWANCES ALLOCATED CAIR*, 2014	CAIR*, 2015 & after
Cayuga	1	100.00	2,621	TBD
Cayuga	2	100.00	2,517	TBD
Cayuga	4	100.00	17	TBD
Connersville	1	100.00	4	TBD
Connersville	2	100.00	4	TBD
Edwardsport	6-1	100.00	7	TBD
Edwardsport	7-1	100.00	202	TBD
Edwardsport	7-2	100.00	191	TBD
Edwardsport	8-1	100.00	165	TBD
Gallagher	1	100.00	596	TBD
Gallagher	2	100.00	615	TBD
Gallagher	3	100.00	670	TBD
Gallagher	4	100.00	630	TBD
Gibson	1	100.00	3,293	TBD
Gibson	2	100.00	3,068	TBD
Gibson	3	100.00	3,283	TBD
Gibson	4	100.00	3,500	TBD
Gibson	5	50.05	1,682	TBD
Henry County	1	100.00	15	TBD
Henry County	2	100.00	16	TBD
Henry County	3	100.00	15	TBD
Madison	1	100.00	12	TBD
Madison	2	100.00	11	TBD
Madison	3	100.00	12	TBD
Madison	4	100.00	22	TBD
Madison	5	100.00	11	TBD
Madison	6	100.00	11	TBD
Madison	7	100.00	11	TBD
Madison	8	100.00	11	TBD
Noblesville Repowering**	1-5	100.00	511	TBD
Vermillion	1	62.50	4	TBD
Vermillion	2	62.50	4	TBD
Vermillion	3	62.50	4	TBD
Vermillion	4	62.50	4	TBD
Vermillion	5	62.50	4	TBD
Vermillion	6	62.50	3	TBD
Vermillion	7	62.50	4	TBD
Vermillion	8	62.50	4	TBD
Wabash River	2	100.00	422	TBD
Wabash River	3	100.00	427	TBD
Wabash River	4	100.00	476	TBD
Wabash River	5	100.00	496	TBD
Wabash River	6	100.00	1,597	TBD
Wheatland	1	100.00	13	TBD
Wheatland	2	100.00	15	TBD
Wheatland	3	100.00	14	TBD
Wheatland	4	100.00	15	TBD
Total Duke Energy Indiana owned units			27,229	

Notes

Number of allowances shown are Duke Energy Indiana's portion for Gibson 5 and Vermillion, rounded.

*CAIR - Clean Air Interstate Rule

The State of Indiana has not yet determined CAIR allocations for 2015 and forward

2015 and forward allocations are expected to be lower than 2014 allocations

**CAIR allocations for Noblesville Repowering include holdover allocations from retired boilers 1-3.

7. ELECTRIC TRANSMISSION FORECAST

All transmission and distribution information is located in Appendix G.

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8. SELECTION AND IMPLEMENTATION OF THE PLAN

A. INTRODUCTION

Once the individual screening processes for demand-side, supply-side, and environmental compliance resources reduced the options to a manageable number, the next step was to integrate these options into the resource plan. This chapter will describe the integration process, the scenario and sensitivity analyses, the selection of the 2013 IRP, and its general implementation.

B. RESOURCE INTEGRATION PROCESS

The goal of the integration process was to take all of the pre-screened EE, supply-side, and the environmental compliance options, and develop an integrated resource plan using a consistent method of evaluation. The tools used in this portion of the process were the Ventyx System Optimizer model and the Ventyx Planning and Risk model.

1. Model Descriptions

System Optimizer

System Optimizer is an economic optimization model that can be used to develop integrated resource plans while satisfying reliability criteria. The model assesses the economics of various resource investments including conventional units (*e.g.*, CTs, CCs, coal units, *etc.*), renewable resources (*e.g.*, wind, solar), and EE resources.

System Optimizer uses a linear programming optimization procedure to select the most economic expansion plan based on Present Value Revenue Requirements (PVRR). The model calculates the cost and reliability effects of modifying the load with demand-side management programs or adding supply-side resources to the system.

Planning and Risk

Planning and Risk is not a generation expansion model. It is principally a very detailed production costing model used to simulate the operation of the electric production facilities of an electric utility.

Key inputs include generating unit, fuel, load, transaction, EE, emissions allowance cost, and utility-specific system operating data. These inputs, along with its complex algorithms, make Planning and Risk a powerful tool for projecting utility electric production facility operating costs.

2. <u>Identify and Screen Resource Options for Future Consideration</u>

The IRP process evaluates EE and supply-side options to meet customer energy and capacity needs. The Company develops EE options for consideration within the IRP based on input from our collaborative partners and cost-effectiveness screening (see Chapter 4). Supply-side options reflect a diverse mix of technologies and fuel sources (gas, coal, nuclear and renewable). The Company compared capacity options within their respective fuel types and operational capabilities, with the most cost-effective options being selected for inclusion in the portfolio analysis phase (see Chapter 5).

Over the 20 year planning period, a 200 MW capacity addition to the Duke Energy Indiana system translates to a 3% increase in reserve margin. Therefore, some of the generic supply-side options were modeled in blocks smaller than either the optimal economic or the commercially available sizes of these units. For example, the CC and nuclear units were modeled in blocks of 340 MW and 280 MW, respectively. Actual units utilizing these technologies are normally much larger.

Using comparably sized units also creates a more level playing field for these alternatives in the model so that choices will be made based on economics rather than being unduly influenced by the sizes of units in comparison to the reserve margin requirement. Supply-side screening typically showed that the largest unit sizes available for any given technology type were the most cost-effective, due to economies of scale. If smaller units were required for Duke Energy Indiana, the capital costs on a $/kW basis would be much higher than the cost estimates used in this analysis. Duke Energy Indiana could take advantage of the economies of scale from a larger unit by jointly owning such a unit with another utility or by signing a power purchase agreement (PPA) from a facility.

There is not currently an Indiana or federal Renewable Energy Portfolio Standard (REPS). However, to assess the impact to the long-term resource need, the Company believes it is prudent to plan for a REPS and each scenario studied included such an assumption. Based on the results of the screening curve analysis and support from the renewable strategy and compliance group, the renewables that were made available to the model were Wind, Solar, and small-scale/landfill-gas Biomass.

Based on the results of the screening analysis, the following technologies in Table 8-A were included in the quantitative analysis as potential supply-side resource options to meet future capacity needs:

Table 8-A Technologies Considered

Technology	Cost Basis (Nominal MW)	Modeled in System Optimizer (Nominal MW)	% Peak Contribution
Nuclear	2,240 (2 units)	280	100%
Simple Cycle CT	800 (4 units)	200	100%
Combined Cycle CC	600 Unfired 80 Duct fired	300 Unfired 40 Duct fired	100%
Wind	50	50	9%
Solar	2	10	42%
Bio-methane	2	2	100%

Projected impacts from both Core and Core Plus EE programs were included. These EE resources reduce the need for new generation resources.

Demand Response programs contain customer-specific contract curtailment options, Power Manager (residential direct load control), and PowerShare® (for non-residential customers). The DR programs were modeled in four discrete groupings:

- Power Manager – Direct Load Control
- Interruptible – Special Contracts
- PowerShare® – Demand Response
- PowerShare® – Behind The Meter Generation

Any generic resources selected by the model represent "placeholders" for the type of capacity needed on the system. The peaking, intermediate, or base load needs can be fulfilled by purchases from the market, cogeneration, repowering, or other capacity that may be economical at the time decisions to acquire new capacity are required. Decisions concerning coordinating the construction and operation of new units with other utilities or entities can also be made at the proper time.

The integration analysis in System Optimizer was performed for a twenty year period (2013-2033). The final detailed production costing modeling in Planning and Risk was performed for the same time period. However, additional years of fixed costs and escalated production costs are included to better incorporate end effects.

C. QUANTITATIVE ANALYSIS RESULTS

1. Define Scenarios

Scenario analysis was included to increase the robustness of the planning process. The initial stakeholder meeting included a discussion of the underlying assumptions and driving forces that define a scenario. Building on that discussion, three scenarios were developed for use in this planning process.

Once the scenarios were specified, an outside consultant was engaged to model each scenario in an internally consistent way. This was done to capture the secondary and tertiary effects caused by changes in a key variable. For example, in the scenarios that include a carbon tax, the higher operating costs of carbon emitting generation results in that generation dispatching less frequently. The consequence of this lower consumption of fossil fuels is that the demand for those fuels decreases and results in lower prices for those fuels.

Many of the assumptions for each scenario represent anticipated environmental requirements consistent with the theme of that scenario. As these environmental rules are formalized, they will be incorporated into future analysis.

While these scenarios do not cover all possible futures, they cover a reasonable range of futures. As more information is learned, it will be incorporated into future IRPs.

Reference Scenario

The Reference Scenario represents the Company's view of the planning period. The scenario assumes a carbon tax in 2020 starting at approximately $17/ton that increases to $50/ton by 2033.

There are no additional SO_2 requirements assumed; however, for NOx control purposes, SCRs are assumed to be required on units larger than 400 MW by 2020; for smaller units, SNCRs are assumed to be required by 2020. Lower intake velocity screens are assumed to be required by mid-2016 to comply with anticipated 316(b) requirements.

Relatively low levels of renewable energy were assumed as a proxy for a state or federally mandated REPS. In this scenario, minimum levels are assumed to be approximately 1% of total sales by 2020 and approximately 5% of total sales by 2033. Regarding energy efficiency, this scenario assumes compliance with the Commission's Phase II Order, reaching 11.9% of retail sales by 2019 and then maintaining 11.9% through 2033.

Fuel prices were developed by modeling these assumptions to determine the impact on fuel markets. This creates a set of fuel curves that are consistent with the other assumptions in the Reference Scenario.

Low Regulation Scenario

The Low Regulation Scenario differs from the Reference Scenario in that it assumes the absence of some additional new environmental regulations, as well as the delay in some regulations assumed in the Reference Scenario. For example, this scenario does not assume the implementation of a carbon tax. Similar to the Reference Scenario's assumption on SO_2 and NOx controls, there are no additional SO_2 requirements, but for NOx control, the requirement for SCRs and SNCRs is delayed 5 years to 2025. Lower intake velocity screens requirements are delayed to 2020 to comply with anticipated 316(b) requirements.

Minimum levels of renewable energy were assumed as a proxy for a state or federally mandated Renewable Portfolio Standard. In this scenario, minimum levels are assumed to be approximately 1% of total sales by 2020 and approximately 4% of total sales by 2033. Regarding energy efficiency, this scenario assumes that reaching 11.9% of the retail sales is not achieved until 2033.

Fuel prices were developed by modeling the above set of assumptions to determine the impact on the fuel markets and, in doing so, this creates a set of fuel curves that are consistent with the other assumptions in Low Regulation scenario.

Environmental Focus Scenario

The Environmental Focus Scenario assumes some additional new environmental regulation as well as the acceleration of some regulations assumed in the Reference Scenario. The Environmental Focus Scenario assumes a carbon tax in 2020 starting at approximately $20/ton and increasing to $75/ton by 2033. In contrast to the other two scenarios, this scenario assumes that all units larger than 400 MW will need a scrubber and SCR by 2020 and that smaller units will need to meet that requirement by 2025. With regard to 316(b), modified intake structures are required by 2018 and units larger than 500 MW sited in coastal or estuary areas will need cooling towers by 2020.

Higher levels of renewable energy were assumed as a proxy for a state or federally mandated REPS. In this scenario, minimum levels were assumed to be approximately 1% of total sales by 2020 and approximately 15% of total sales by 2033. Regarding energy efficiency, this scenario assumes reaching 11.9% of retail sales by 2019 and increasing to 15% by 2032.

Fuel prices were developed by modeling these assumptions to determine the impact on the fuel markets. This creates a set of fuel curves consistent with the other assumptions in Environmental Focus Scenario.

2. **<u>Evaluate Retirements and Environmental Control Equipment in each Scenario</u>**

The Company must objectively determine the viability of generating units that are at risk due to the forecasted regulatory outcomes of each scenario. Each unit is assigned a project list that ensures compliance with anticipated regulations. The estimated costs of these projects and their impacts on unit operations are determined. The most at-risk assets are evaluated first and the decision to retire or control the unit(s) is then used as an input for the next retirement analysis. The 2013 IRP incorporates retirement decisions for over 4,400 MW of generation. The hierarchy of units included in the retirement analysis are:

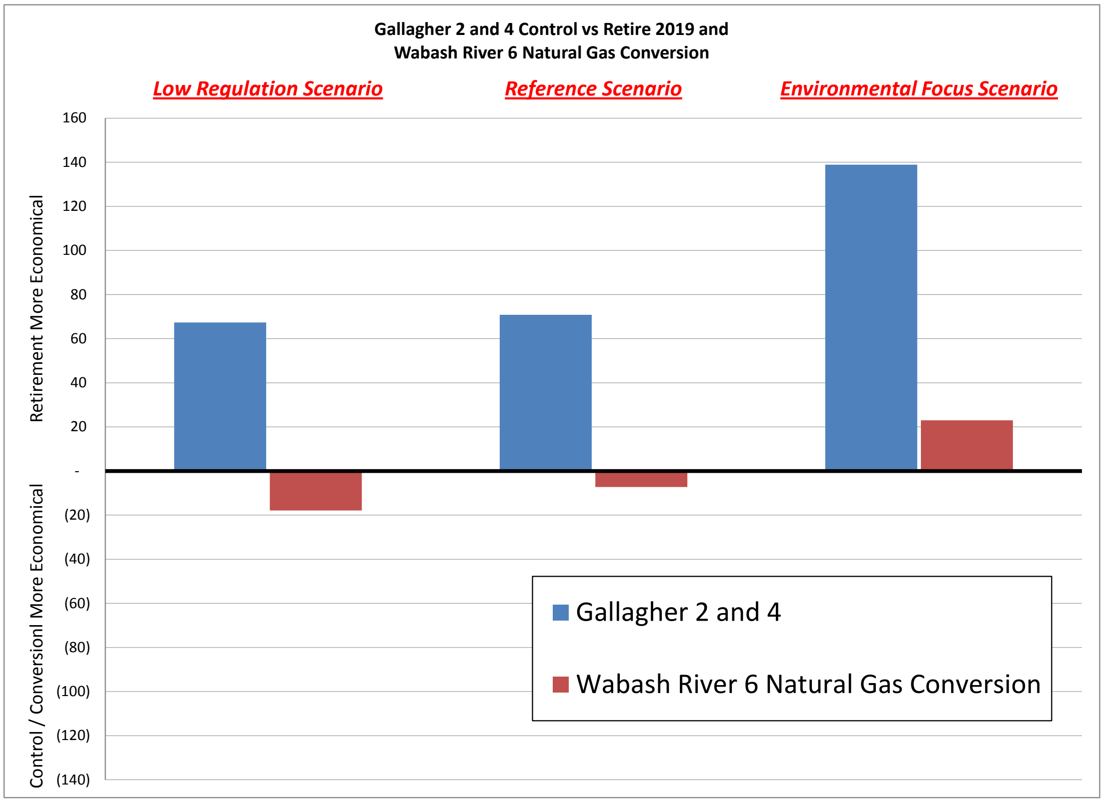
1. Gallagher 2 and 4
2. Wabash River 6 with the option for Natural Gas Conversion
3. Gibson 5
4. Gibson 1 and 2
5. Gibson 3 and 4
6. Cayuga 1 and 2

Retirement Decision Analysis Results

Based on the "retirement decision hierarchy", the viability of Gallagher 2 and 4 was analyzed first due to anticipated future regulations potentially requiring significant investments in 2019. In all three scenarios, it appears that investment to meet environmental regulations beyond 2019 is not economically justified. As a result, a 2019 retirement date for these units was assumed from this point further as additional retirement candidates were studied. However, the final decision to retire Gallagher 2 and 4 in 2019 will not be made until later. These units will continue to be evaluated in the future as regulatory rules become clearer.

Under the "hierarchy," the Wabash River 6 natural gas conversion was then analyzed under the assumption that Gallagher 2 and 4 are retired in 2019. Based on an assumed 15 year life, the natural gas conversion is expected to provide value for customers under both the Reference and Low Regulation scenarios. However, in the Environmental Focus Scenario, retirement of Wabash River Unit 6 was more economical than gas conversion. The results of the Gallagher and Wabash River analyses are shown in Figure 8-A.

Figure 8-A



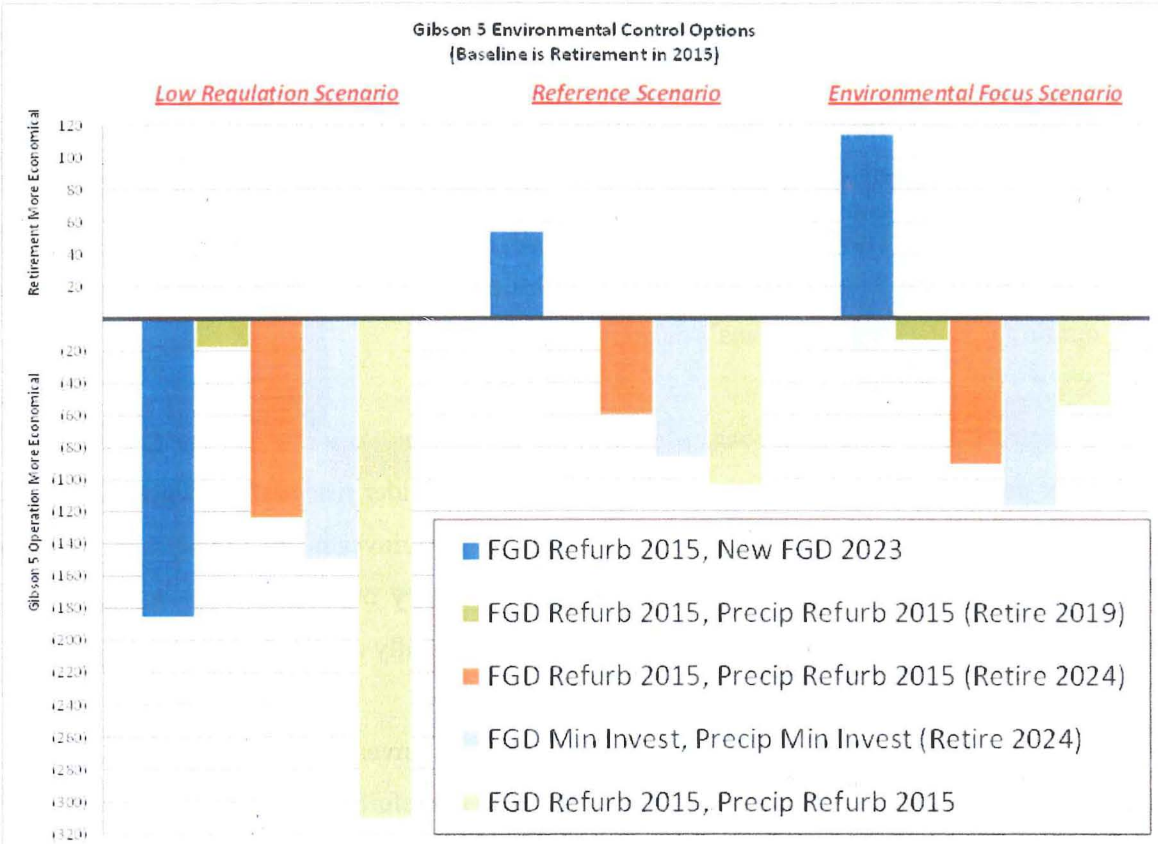
For the Gibson Station Unit 5 assessment, multiple investment alternatives and timing options were considered. The primary investments being analyzed on this unit are in the refurbishment of the existing electrostatic precipitator as well as the existing FGD. Multiple scopes of work on this equipment were assessed, and ranged from short term investment life to longer term investment life. Alternative retirement decision dates were analyzed for all scenarios. Forecasted compliance dates associated with MATS, CCR, and Ozone NAAQS drove the timing of these alternative retirement dates. Under all scenarios, retirement before 2020 is uneconomic. However, investing in Gibson 5 through 2023 (retirement before the summer of 2024) appears to be the most economic option in the Environmental Focus scenario.

However, it should be noted that while Duke Energy Indiana has put substantial effort into developing detailed costs for the full refurbishment scopes of work for both the precipitator and FGD, the minimum investment case (“min invest”) scopes of work and cost estimates should be considered placeholders for analytical purposes because they have not yet been vetted by engineering or vendor bidding. Duke Energy Indiana is awaiting the results of a recent inspection of the precipitator to determine whether any decrease in the level of investment from the full scope refurbishment is possible before making a final investment decision. Even though no decision has yet been made on the final scope of the precipitator refurbishment, our results demonstrate that absent a requirement to replace the existing FGD, investment in and continued operation of Gibson 5 through at least 2024 is a lowest cost option for Duke Energy Indiana's customers.

Gibson 5 has a vintage scrubber installed at the time the unit went in service. Due to this and other unit-specific characteristics, Gibson Unit 5 has a wider risk profile than the other units at Gibson Station with more recent environmental control investments. More than 10 options were identified as solutions to meet potential regulatory outcomes. The most important results of these analyses are discussed below and graphically depicted in Figure 8-B.

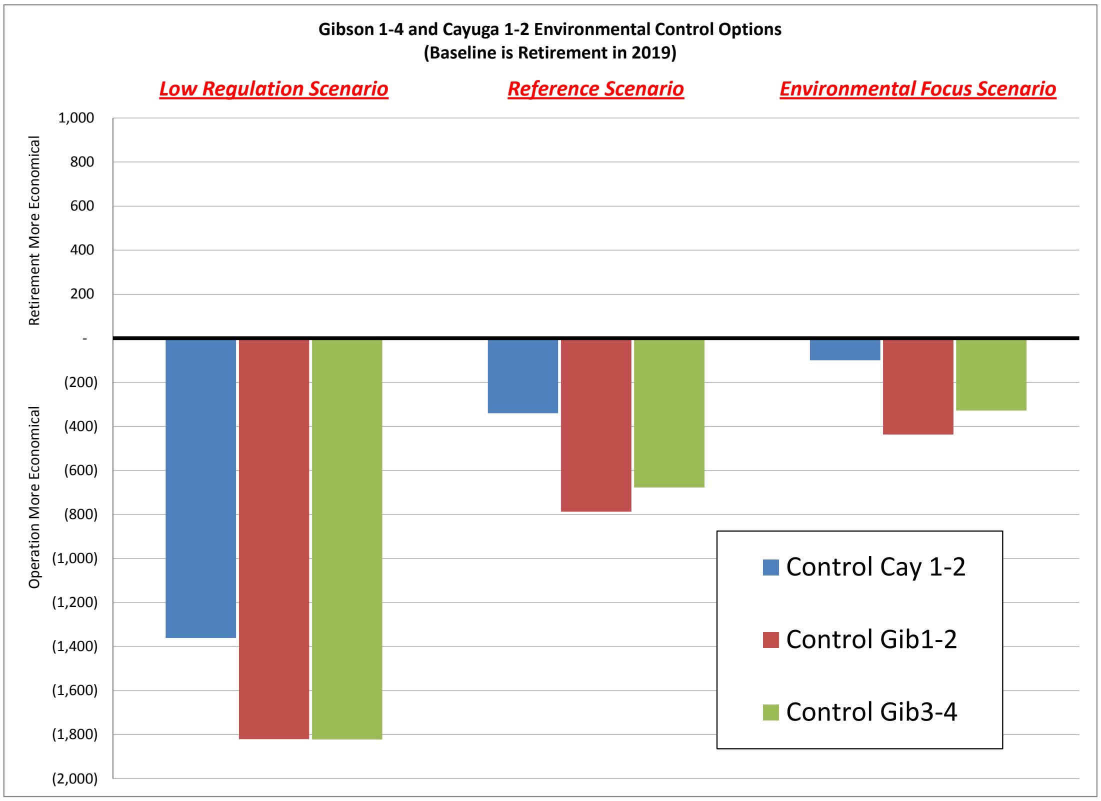
Under the Reference and Low Regulation scenarios, investing in Gibson 5 through the planning horizon with a refurbished precipitator and refurbished FGD is the appropriate action plan. At this time, it is cost prohibitive to install a new FGD under the Reference and Environmental Focus Scenarios. However, under a Low Regulation scenario, a new FGD on Gibson 5 is economical. In all scenarios, installation of the new FGD is assumed in 2023 at a cost of approximately $570/kW. Alternative retirement decision dates were analyzed for all scenarios. Forecasted compliance dates associated with MATS, CCR, and Ozone NAAQS drove the timing of these alternative retirement dates. Under all scenarios, retirement before 2020 is uneconomic. However, investing in Gibson 5 through 2023 (retirement before the summer of 2024) is the most economic option in the Environmental Focus scenario.

Figure 8-B



Analysis of the long term viability of Duke Energy Indiana's larger coal assets is shown in Figure 8-C. Significant customer benefits are expected in all three scenarios. However, the Environmental Focus Scenario's more stringent environmental regulations, including a \$75/ton CO_2 cost in 2033, add insurmountable cost to all the pulverized coal units. In addition to the units retired in the Low Regulation and Reference Scenarios, the additional CO_2 cost in the Environmental Focus Scenario causes the retirement of Gibson 1-4 and Cayuga 1&2 in the early to mid-2030s in that scenario.

Figure 8-C



3. <u>Develop portfolios for each scenario</u>

Once the scenarios were specified, the capacity expansion model (SO) was run for each scenario and included the retirement analysis decisions described in the previous section. The result was the development of three portfolios that were analyzed further in all of the scenarios as well as a variety of sensitivities. Tables 8-B and 8-C show a comparison of the key characteristics of the three portfolios. Figure 8-D shows the changes in the capacity mix and energy mix between 2013 and 2033. The relative shares of renewables, energy efficiency, and gas all increase, while the relative share of coal decreases.

Blended Approach Portfolio

The Blended Approach Portfolio was the optimal portfolio selected by SO for the assumptions in the Reference Scenario and includes the retirements described for that scenario. New resources include converting Wabash River 6 to natural gas, CT and CC capacity, and some nuclear capacity in the 2030's. This portfolio also includes 14% of total sales being met by renewable resources.

Traditional Portfolio

The Traditional Portfolio was the optimal portfolio selected SO for the assumptions in the Low Regulation Scenario and includes the retirements described for that scenario. New resources include converting Wabash River 6 to natural gas, as well CT and CC capacity. This portfolio does not include any nuclear capacity. The Traditional portfolio also includes 4% of total sales being met by renewable resources.

Coal Retires Portfolio

The Coal Retires Portfolio was the optimal portfolio selected by SO for the assumptions in the Environmental Focus Scenario and includes the retirements described for that scenario. New resources include CTs, CCs, and nuclear capacity. This portfolio also includes 15% of total sales being met by renewable resources.

Table 8-B: Summary of Portfolios

TRADITIONAL PORTFOLIO (Optimized for Low Regulation Scenario)

	2014-2018	2019-2023	2024-2028	2029-2033	Energy Efficiency (% of Retail Sales)	Renewable Energy (% of Total Sales)
Retirements	WR 2-6 Coal Connersville 1-2 CT MW 1-3, 5 & 6 CT	Gall 2,4 Coal		WR 6 NG Conversion	6% in 2020 12% in 2032	2% in 2020 4% in 2032
Additions	WR 6 NG Conversion New CT (400 MW)	New CT (600 MW)	New CT (400 MW)	New CC (680 MW)		

BLENDED APPROACH PORTFOLIO (Optimized for Reference Scenario)

	2014-2018	2019-2023	2024-2028	2029-2033	Energy Efficiency (% of Retail Sales)	Renewable Energy (% of Total Sales)
Retirements	WR 2-6 Coal Connersville 1-2 CT MW 1-3, 5 & 6 CT	Gall 2,4 Coal		WR 6 NG Conversion	12% in 2020 12% in 2032	3% in 2020 14% in 2032
Additions	WR 6 NG Conversion	New CT (600 MW)	New CC (340 MW) New CT (200 MW)	New CC (340 MW) New Nuclear (280 MW)		

COAL RETIRES PORTFOLIO (Optimized for Environmental Focus Scenario)

	2014-2018	2019-2023	2024-2028	2029-2033	Energy Efficiency (% of Retail Sales)	Renewable Energy (% of Total Sales)
Retirements	WR 2-6 Coal Connersville 1-2 CT MW 1-3, 5 & 6 CT	Gall 2,4 Coal	Gibson 5 Coal	Cayuga 1,2 Coal Gibson 1-4 Coal	12% in 2020 15% in 2032	4% in 2020 15% in 2032
Additions	New CT (400 MW)	New CT (200 MW)	New CC (340 MW) New CT (600 MW)	New CC (2380 MW) New Nuclear (1120 MW) New CT (170 MW)		

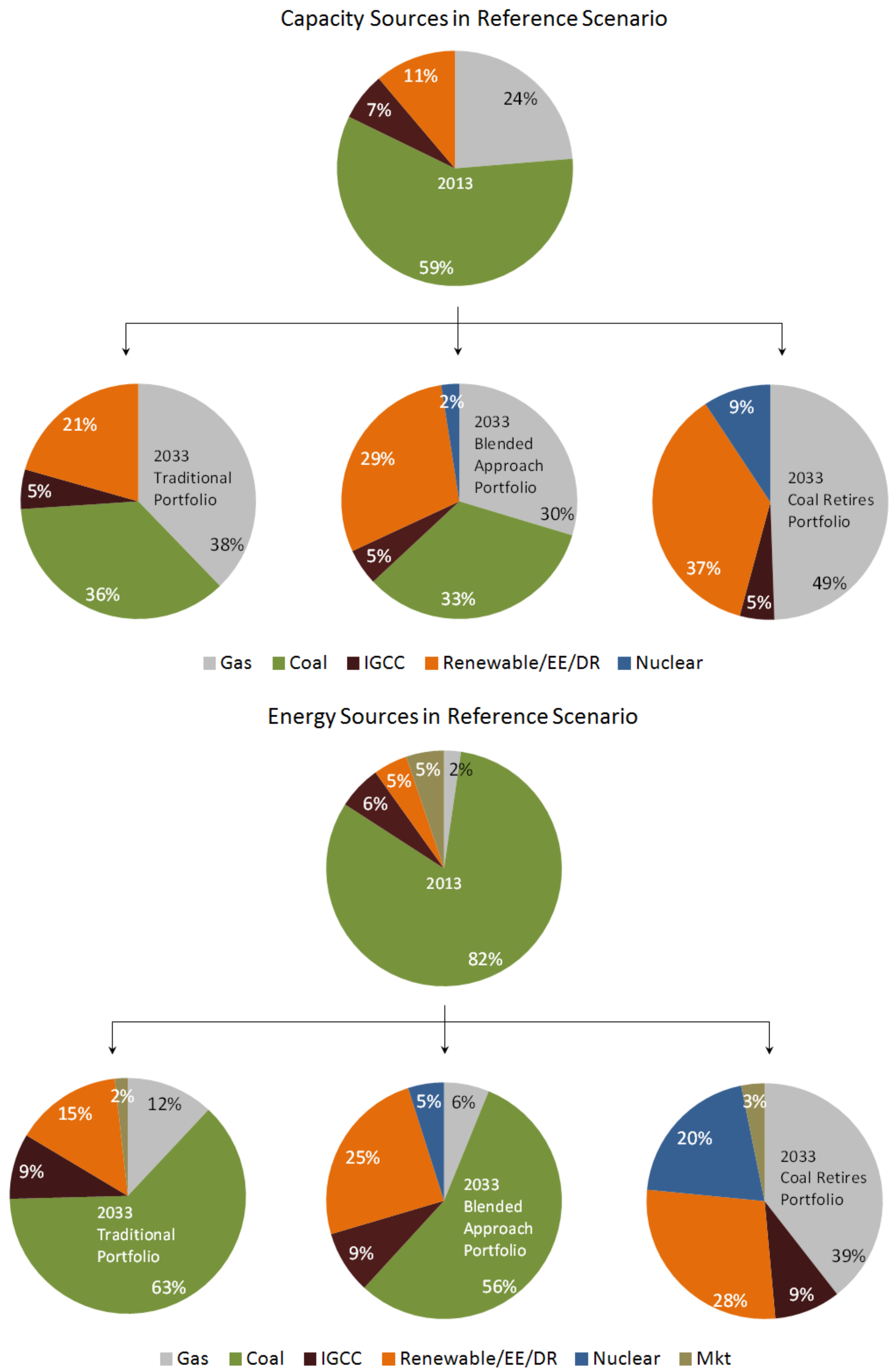
Table 8-C – Portfolios Evaluated At Summer Peak MW

Non-Renewables	Portfolio		
Year	Traditional	Blended Approach	Coal Retires
2012			
2013			
2014			
2015			
2016	318 MW (WR6 NG)	318 MW (WR6 NG)	200 MW (CT)
2017	200 MW (CT)		
2018	200 MW (CT)		200 MW (CT)
2019	200 MW (CT)	200 MW (CT)	200 MW (CT)
2020	200 MW (CT)	200 MW (CT)	
2021			
2022	200 MW (CT)		
2023		200 MW (CT)	
2024			400 MW (CT)
2025	200 MW (CT)	200 MW (CT)	200 MW (CT)
2026			
2027		340 MW (CC)	
2028	200 MW (CT)		340 MW (CC)
2029			
2030		340 MW (CC)	
2031	680 MW (CC)	280 MW (Nucl)	
2032			680 MW (CC) 560 MW (Nucl)
2033			170 MW (CT) 1700 MW (CC) 560 MW (Nucl)
Total CT	1400	800	1370
Total CC	680	680	2720
Total Nuclear	0	280	1120
Total Nat Gas Conversion	318	318	0
Total Coal Retirements	948	948	4739
Total Gas Retirements	484	484	166

Table 8-C – Portfolios Evaluated At Summer Peak MW (Continued)

Renewables	Portfolio								
Year	Traditional			Blended Approach			Coal Retires		
	Solar	Wind	Biomass	Solar	Wind	Biomass	Solar	Wind	Biomass
2012									
2013									
2014									
2015									
2016									
2017									
2018	25		4	25		4	25		4
2019	9	4		13	4		25	9	2
2020	8	5		8	5	2	21	9	2
2021	8		2	13	4		34	4	2
2022	9	4		8	5	2	17	9	2
2023	12		2	13			29	9	4
2024	17	5		12	4	2	21	9	2
2025		4	2	17	5	2	30	9	3
2026	9			30	22		25	9	2
2027	8	9	2			2	25	9	4
2028		4						9	
2029							4	27	
2030	4								
2031					22		4		
2032					54		5	52	
2033					53			9	
Total	109	35	12	139	178	14	265	173	27
Total at Peak	156			331			465		
Total Nameplate	672			2344			2606		

Figure 8-D Generation Mix 2013 and 2033



4. Portfolio Analysis

Scenario Analysis

As discussed previously, scenario analysis was included to increase the robustness of the planning process. In doing this, a broader range of internally consistent views of the future can be considered to inform the effort to develop a robust portfolio that minimizes the PVRR.

The scenarios create a framework for the evaluation of each of the portfolios under a range of different possible futures. For example, questions such as "How would the Traditional Approach portfolio do in an Environmental Focus world?" or "Which portfolio is most costly in each scenario?" are very useful questions in deciding on the which portfolio to select for the IRP.

Sensitivity Analysis

Sensitivities provide a secondary level of analysis that addresses the responsiveness of a given portfolio to changes in key variables. Scenario analysis represents a more realistic view of how a given portfolio performs under a variety of assumptions since each variable does not change completely independently other key variables. Making statements that portfolio A is better than portfolio B because it has lower costs if gas prices increase $2/MMBtu is not a fair claim since there would be secondary effects on the dispatch of gas generation, the market prices of power, and overall demand for natural gas. What can be fairly stated is that portfolio A is less sensitive than Portfolio B to increases in natural gas prices and thus has less risk with respect to gas prices. The sensitivity analysis will focus on assessing the responsiveness and risk impact of the three portfolios to changes in key variables and that will be used to supplement the scenario analysis is the selection of the portfolio for the IRP.

5. Analysis Results

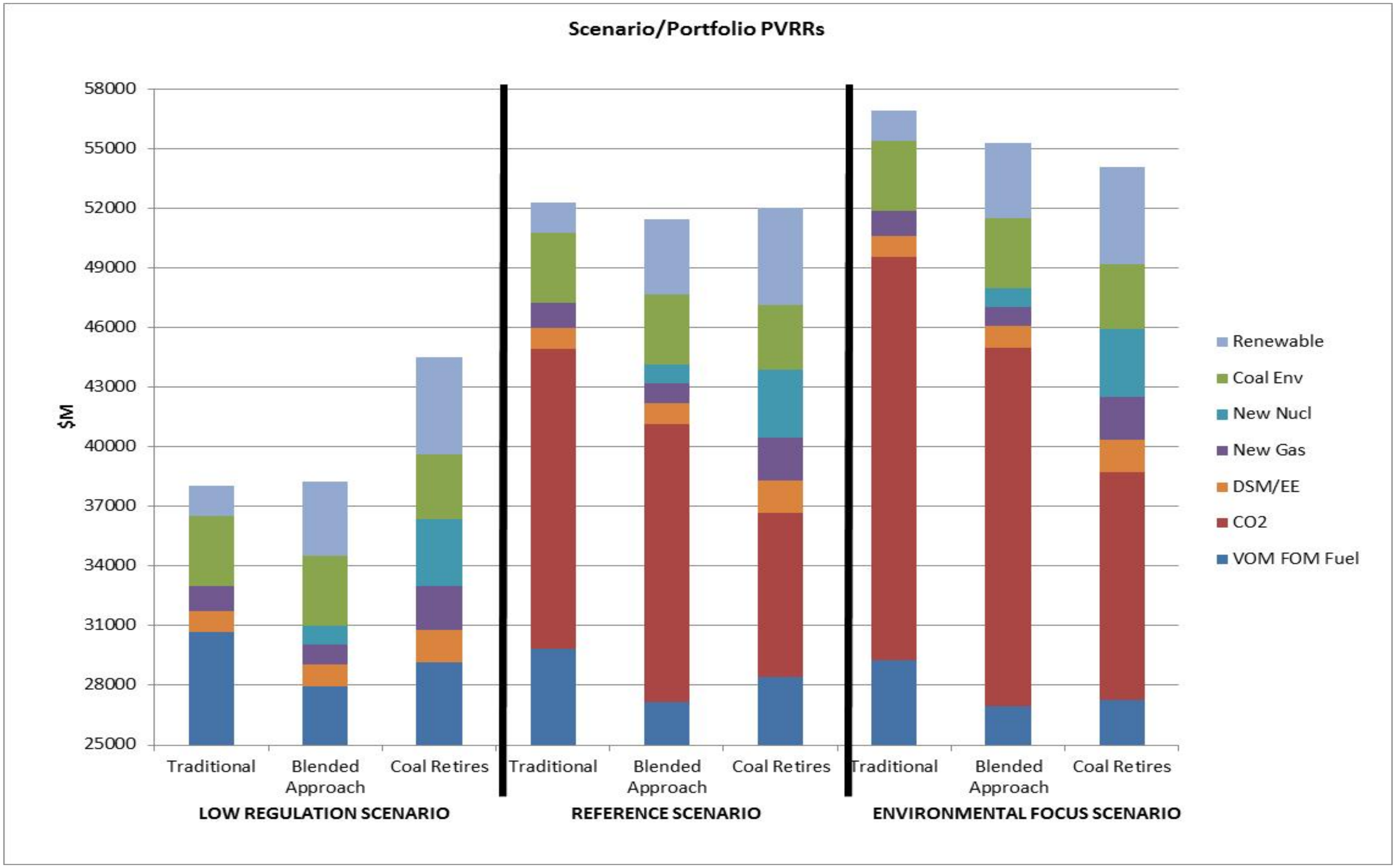
Once the optimal portfolios were developed using SO, the next level of analysis included detailed production modeling using the PaR model. All three portfolios were modeled in all three scenarios using PaR. In Table 8-D, the three scenarios are shown in columns and the portfolios in rows. The body of the table shows the PVRRs of all of the combinations of scenarios and portfolios. For example, The PVRR cost (40-year MM$) of the Traditional Portfolio in the Low Regulation scenario is $38,014. The shaded cells identify the PVRR of the portfolio that was optimized for that scenario. Figure 8-E shows the components of the PVRRs in Table 8-D. In both the Reference Scenario and the Environmental Focus Scenario, CO_2 is the largest cost component.

Table 8-D: Portfolio PVRRs in Each Scenario

PVRR (MM$)		SCENARIOS		
		LOW REGULATION	REFERENCE	ENVIRONMENTAL FOCUS
PORTFOLIOS	TRADITIONAL	$38,014	$52,261	$56,889
	BLENDED APPROACH	$38,258	$51,420	$55,273
	COAL RETIRES	$44,493	$51,999	$54,051

It is instructive to look at the cost of each portfolio in a given scenario, particularly those that were not optimal for that scenario. This is beneficial for measuring portfolio robustness over a range of potential future outcomes. In general, the costs of all of the portfolios increase as one goes across a given row in Table 8-D. This is due to each scenario having a higher carbon tax assumption than the scenario to the left of it. Below are some observations of the scenario analyses.

Figure 8-E: PVRR Components



Low Regulation Scenario

In the Low Regulation scenario, the Traditional Portfolio performs best by leveraging the existing fleet, benefiting from new gas generation, and foregoing nuclear additions due to the absence of a CO_2 cost. Next in order of increasing costs is the Blended Approach Portfolio, which also leverages the existing fleet and the benefits of new gas generation. It also includes the added cost of constructing nuclear generation later in the planning period but does not include any offsetting value from the reduction in CO_2 emissions due to the absence of a carbon tax in this scenario. The Coal Retires Portfolio is the most costly portfolio in this scenario primarily due to the retirement of the large coal units and replacing them with CC and nuclear capacity, but with no benefit from its lower CO_2 emissions.

Reference Scenario

In the Reference Scenario, the Blended Approach Portfolio performs best by leveraging the existing fleet of resources and the benefits of new gas generation. The Coal Retires Portfolio, with additional nuclear capacity in the early 2030s, begins to benefit from its lower carbon emissions. In this scenario, the Traditional Portfolio is most costly, which is primarily due to the imposition of a carbon tax on its fossil fuel generation.

Environmental Focus Scenario

In the Environmental Focus Scenario, the Coal Retires Portfolio performs best with benefits from the presence of a higher carbon tax assumption that required the additional expense of retiring the existing coal fleet and constructing a nuclear unit. The Blended Approach Portfolio is the next most cost effective portfolio. Because this portfolio did not incur as much investment to reduce carbon emissions as the Coal Retires Portfolio, it does not benefit as much from the higher CO_2 cost assumption in this scenario. Because the Traditional Portfolio was optimized for the Low Regulation Scenario with no CO_2 cost, its investments were selected with no financial incentive for reducing CO_2 emissions. In the Environmental Focus scenario, the Traditional Portfolio incurs greatest costs due to its more carbon-intensive generation.

6. Portfolio Performance Under Different Scenario Probability Assumptions

It is worthwhile to evaluate the portfolios under a range of probabilities for each scenario. One could simply average the portfolio columns in Table 8-D, but this would imply that each scenario is equally likely. Rather than attempting to guess the probability of each scenario, combinations of scenario probabilities were modeled in 10% increments to evaluate:

- What portfolio is most often the least cost portfolio?
- What portfolio is least often the most costly portfolio?

Least Cost Portfolio Analysis

Figure 8-F shows which portfolio is least cost for any combination of scenario probabilities. The vertical axis shows the probability of the Low Regulation Scenario. The horizontal axis shows the probability of the Environmental Focus Scenario. This arrangement results in the Reference Scenario having a probability of 100% minus the sum of the probabilities of the other two scenarios. For example, if the Low Regulation Scenario is assumed to be 30% likely and the Environmental Focus Scenario 40% likely, then at the intersection of those two assumptions, the probability of the Reference Scenario would be 30%.

Figure 8-F: Least Cost Porftolio by Scenario Probablility

LEAST COST PORTFOLIO

LOW REG SCENARIO PROBABILITY	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
100%	T										
90%	T	T									
80%	T	BA	BA								
70%	BA	BA	BA	BA							
60%	BA	BA	BA	BA	BA						
50%	BA	BA	BA	BA	BA	BA					
40%	BA	BA	BA	BA	BA	BA	BA				
30%	BA	BA	BA	BA	BA	BA	BA	BA			
20%	BA	BA	BA	BA	BA	BA	BA	BA	BA		
10%	BA	BA	BA	BA	BA	BA	BA	CR	CR	CR	
0%	BA	BA	BA	BA	CR	CR	CR	CR	CR	CR	CR

ENVIRONMENTAL FOCUS SCENARIO PROBABILITY

T = Traditional Portfolio
BA = Blended Approach Portfolio
CR = Coal Retires Portfolio

Looking at the three portfolios from this perspective gives insight into the relative costs of each portfolio in an uncertain future but also helps explain under what conditions a portfolio is the least cost option. Based on these results, there are two key observations:

1. The Blended Approach Portfolio is most frequently the least cost portfolio
2. Only when the probability assumptions are heavily weighted toward the Low Regulation or Environmental Focus scenarios do the Traditional Portfolio or Coal Retires Portfolio, respectively, become the least cost option.

Highest Cost Portfolio Analysis

It is also worthwhile to look at the probability combinations that would cause a portfolio to be highest cost. Figure 8-G shows the highest cost portfolio for any combination of scenario probabilities using the same format as Figure 8-F.

Figure 8-G: Highest Cost Porftolio by Scenario Probablility

HIGHEST COST PORTFOLIO

LOW REG SCENARIO PROBABILITY

100%	CR										
90%	CR	CR									
80%	CR	CR	CR								
70%	CR	CR	CR	CR							
60%	CR	CR	CR	CR	CR						
50%	CR	CR	CR	CR	CR	CR					
40%	CR	CR	CR	CR	CR	CR	CR				
30%	CR	CR	CR	CR	CR	CR	CR	T			
20%	CR	CR	CR	CR	CR	T	T	T	T		
10%	CR	CR	T	T	T	T	T	T	T	T	
0%	T	T	T	T	T	T	T	T	T	T	T
	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%

ENVIRONMENTAL FOCUS SCENARIO PROBABILITY

T = Traditional Portfolio
BA = Blended Approach Portfolio
CR = Coal Retires Portfolio

Based on these results, there are two key observations:

1. The Blended Approach Portfolio is never the highest cost portfolio
2. When the probability assumptions are weighted toward the Low Regulation Scenario, the Coal Retires Portfolio is the highest cost option. When the probability assumptions are weighted toward the Environmental Focus Scenario, the Traditional Portfolio becomes the highest cost option.

Initial Conclusions

Based on the evaluation of the three portfolios in various likelihoods of the three scenarios, the Blended Approach Portfolio appears to be the least cost and most robust of the three portfolios.

7. <u>Sensitivity Analysis</u>

Sensitivity analysis provides additional insight into the expected behavior of the three portfolios in response to independent changes in key variables. As discussed previously, a lower relative PVRR as part of sensitivity does not make a portfolio better since the analysis does not incorporate the secondary effects of changing one key variable. It does, however, provide insight into the sensitivity of a portfolio to changes in variables and, on that basis, comparisons can be made.

CO_2 Sensitivity

A direct cost on carbon emissions can have a significant impact on the cost of a portfolio. For emission rates of traditional coal units, every dollar per ton of CO_2 emission adds approximately $1/MWh to the energy cost. For example, if the variable cost to generate a MWh from a coal unit is $30/MWh and there is a $20/ton cost of CO_2 emissions, then the cost of energy with the CO_2 emission cost is approximately $50/MWh.

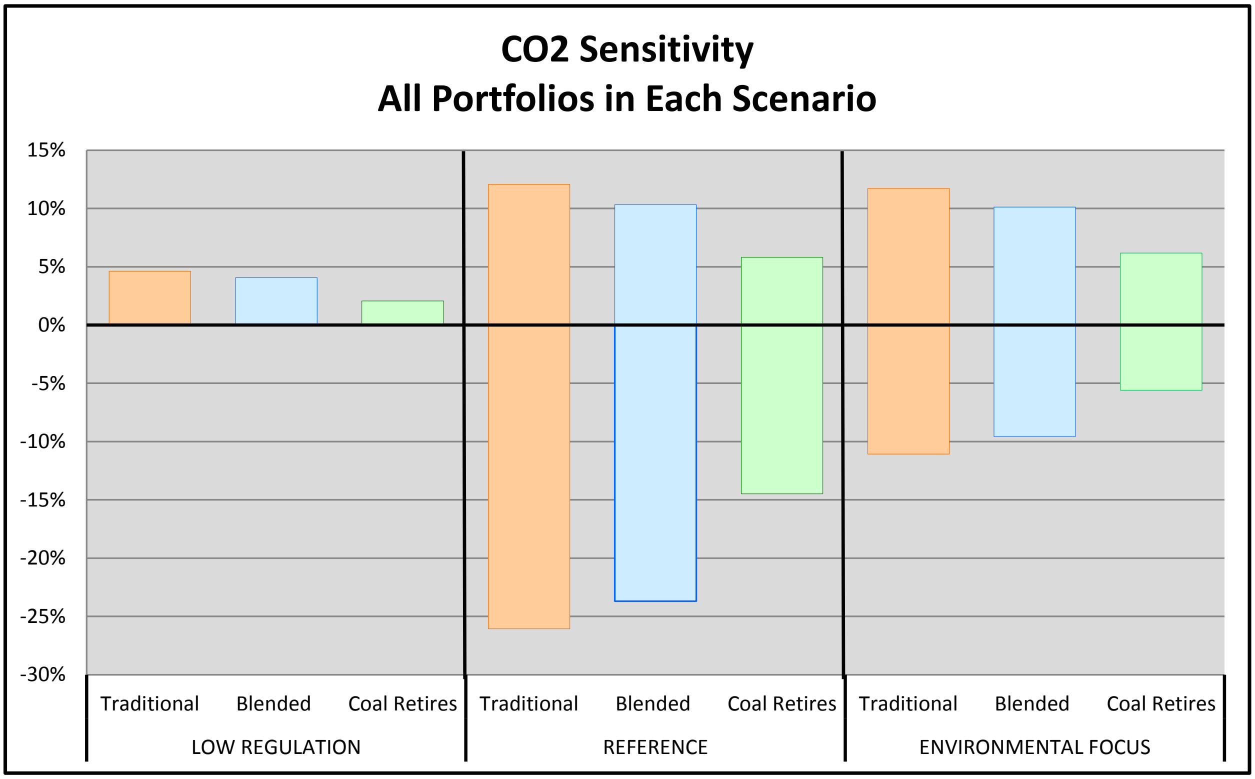
For a natural gas CC, for every dollar per ton of CO_2 emission, approximately $0.50/MWh will be added to the cost of energy. Assuming a variable cost of $24/MWh and a $20/ton carbon tax, the cost of energy with the CO_2 emission cost is $34/MWh.

Because the base case assumption for the Low Regulation Scenario does not include a carbon tax, a low CO_2 sensitivity in that scenario was not performed. Table 8-E defines the CO_2 sensitivities evaluated. Figure 8-H shows how much each portfolio's PVRR cost responds to CO_2 cost changes.

Table 8-E: CO_2 Sensitivities

	SCENARIOS		
	Low Regulation	Reference	Environmental Focus
High Sensitivity	\$5/tn in 2025; \$7/tn in 2033	\$20/tn in 2020; \$75/tn in 2033	\$25/tn in 2020; \$100/tn in 2033
Base Assumption	\$0/tn	\$17/tn in 2020; \$50/tn in 2033	\$20/tn in 2020; \$75/tn in 2033
Low Sensitivity	NA	\$5/tn in 2025; \$7/tn in 2033	\$17/tn in 2020; \$50/tn in 2033

Figure 8-H: CO_2 Sensitivity



The responsiveness of each portfolio was evaluated in each scenario. The Coal Retires Portfolio is the least sensitive to changes in CO_2 prices. If CO_2 prices are higher than the base assumption, the Coal Retires Portfolio would see less of an increase in total costs. If CO_2 prices are lower, the Coal Retires Portfolio cost would decrease less than the others.

At the other end of the spectrum, the Traditional portfolio has the greatest sensitivity to higher CO_2 prices, but also benefits the most if CO_2 prices are lower than the base assumption.

Load Growth Sensitivity

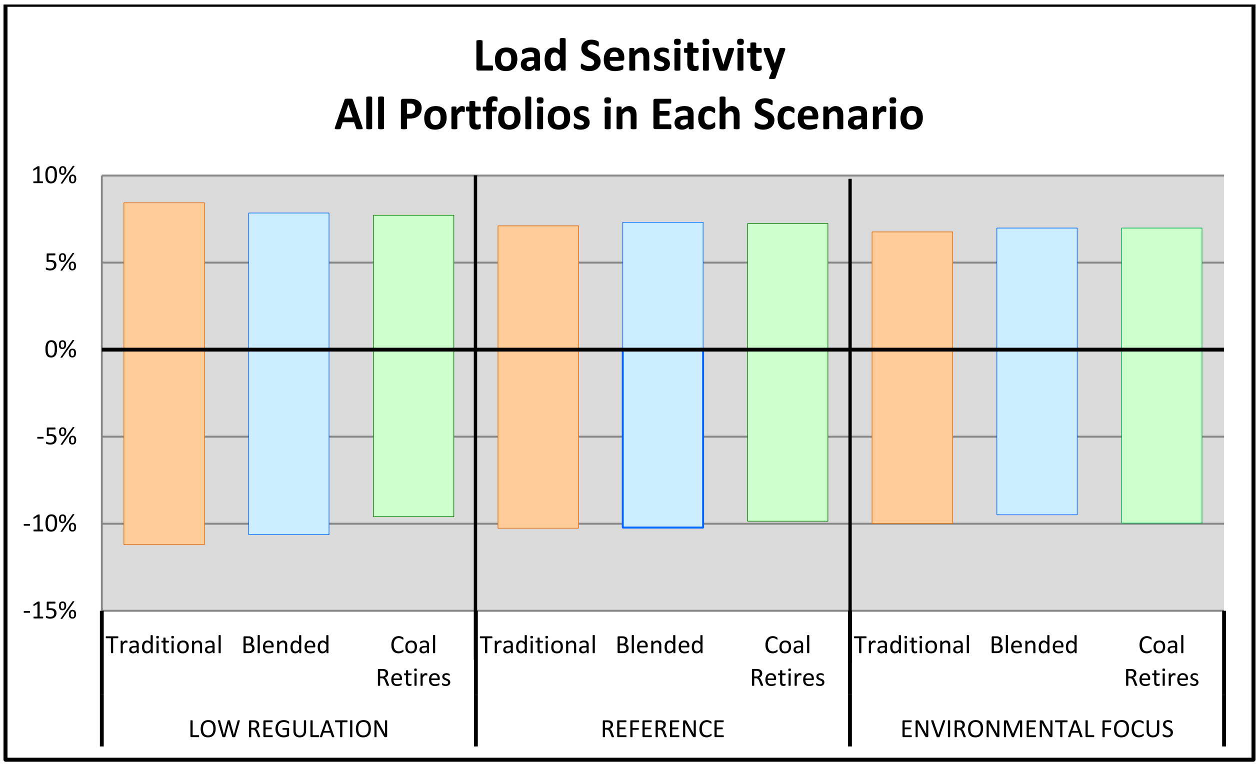
The load sensitivity was developed based on internal load forecasting models. Details of the load forecasting sensitivity are discussed in Section 3.5.

Table 8-F defines the load sensitivities evaluated. Each scenario featured the same load forecast and high and low sensitivities. Figure 8-I shows how much each portfolio's PVRR cost responds to load growth changes.

Table 8-F: Load Growth Sensitivities

	SCENARIOS		
	Low Regulation	**Reference**	**Environmental Focus**
High Senstivity	approx +9% of base case in 2033 (MW)	approx +9% of base case in 2033 (MW)	approx +9% of base case in 2033 (MW)
Base Assumption	0.95% CAGR (after EE)	0.95% CAGR (after EE)	0.95% CAGR (after EE)
Low Sensitivity	approx -13% of base case in 2033 (MW)	approx -13% of base case in 2033 (MW)	approx -13% of base case in 2033 (MW)

Figure 8-I: Load Growth Sensitivity



Sensitivity to changes in load is not a significant differentiating factor between the three portfolios. In response to higher load, each portfolio would likely select resources sooner. The reverse would be true for lower load levels where a portfolio would delay resources to match the need.

Renewable Energy Sensitivity

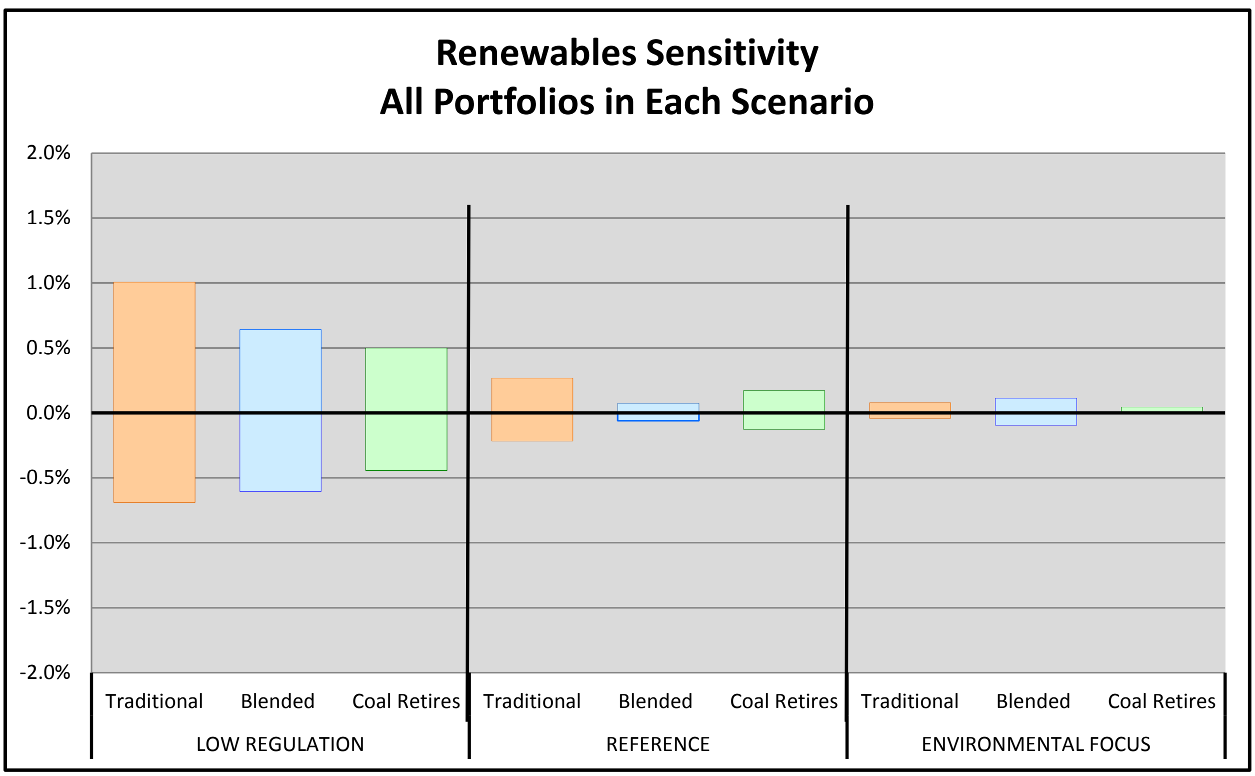
The renewable energy sensitivity was modeled with a higher or lower renewable energy requirement. In general, a higher renewable energy requirement would require each portfolio to add more renewable energy resources and delay add other types of generation; a lower energy requirement would require each portfolio to reduce renewable energy resources and other types of generation.

Table 8-G defines the renewable energy sensitivities evaluated. Figure 8-J shows how each portfolio's PVRR responds to changes in renewable energy levels.

Table 8-G: Renewables Sensitivities

	SCENARIOS		
	Low Regulation	**Reference**	**Environmental Focus**
High Senstivity	Additional 2% of Total Sales	Additional 2% of Total Sales	Additional 2% of Total Sales
Base Assumption	4% of Total Sales	14% of Total Sales	15% of Total Sales
Low Sensitivity	Reduction of 2% of Total Sales	Reduction of 2% of Total Sales	Reduction of 2% of Total Sales

Figure 8-J: Renewables Sensitivity



The results of this sensitivity highlight the differences between the scenarios in addition to the differences between the portfolios. The cost impact of changing the level of renewables in a scenario is inversely related to the magnitude of a price on carbon. For example, adding more renewable energy to the Low Regulation scenario has the greatest impact since there is no offsetting value from carbon-free renewable energy. The impact of changing renewable energy levels is lowest in the Environmental Focus scenario.

When comparing portfolios, the first item of note is the relatively low impact to all portfolio-scenario combinations (less than 1%). The second is that the Coal Retires portfolio is, generally speaking, the least sensitive to changes in renewable levels. Differences between the portfolios in the Reference and Environmental Focus scenarios are also due to slight changes in the timing of CT's to accommodate the different levels or renewable energy. When taken together, this sensitivity has less than a 0.5% impact in these two scenarios.

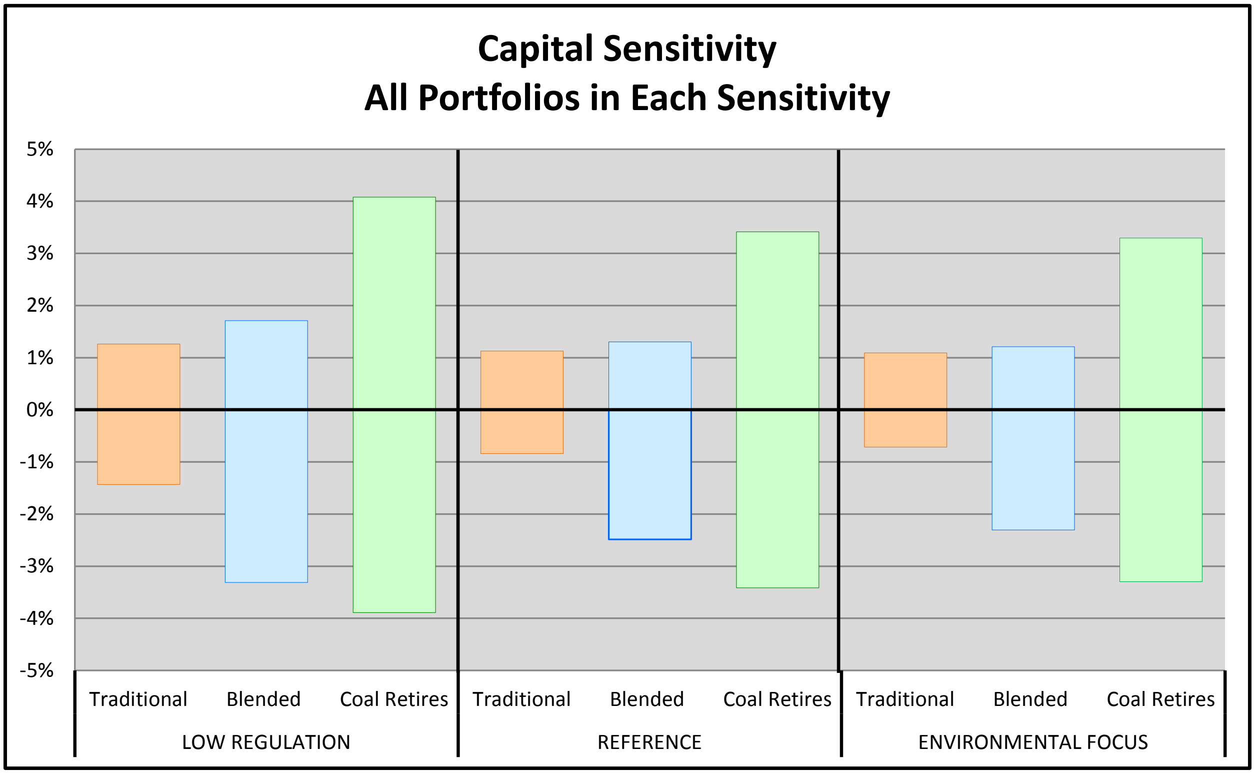
Capital Cost Sensitivity

The capital cost sensitivity considers cost changes for traditional generation, environmental controls, and solar and wind generation. Capital costs were consistent across the three scenarios under base conditions and have the same high and low sensitivities. In all scenarios, the high sensitivity increases CC, CT, and nuclear generation cost by 30%, environmental controls equipment by 20%, and holds solar and wind generation to their base assumption levels. The low sensitivity reduces CC, CT, and nuclear generation and environmental controls equipment by 5%. Solar and wind generation costs are reduced by 30% to reflect additional future technical innovation or the extension of tax credits. These are summarized in Table 8-H. Figure 8-K shows how each portfolio's PVRR responds to capital cost changes.

Table 8-H: Capital Cost Sensitivities

	SCENARIOS		
	Low Regulation	Reference	Environmental Focus
High Senstivity	CC, CT & Nuclear +30%; Controls +20%; Solar & Wind- same as Base Assumption	CC, CT & Nuclear +30%; Controls +20%; Solar & Wind- same as Base Assumption	CC, CT & Nuclear +30%; Controls +20%; Solar & Wind- same as Base Assumption
Base Assumption	Reference Scenario Assumptions	Reference Scenario Assumptions	Reference Scenario Assumptions
Low Sensitivity	CC, CT, Nuclear & Controls -5%; Solar & Wind - 30%	CC, CT, Nuclear & Controls -5%; Solar & Wind - 30%	CC, CT, Nuclear & Controls -5%; Solar & Wind - 30%

Figure 8-K: Capital Cost Sensitivity



Holding the portfolios constant, the results of the capital sensitivity are similar across the three scenarios. Due to not having to replace significant capacity due to retirements and the relatively low cost of adding CT and CC capacity, the Traditional Portfolio is least sensitive to changes in capital costs. The Blended Approach Portfolio is more sensitive due to the addition of capital-intensive nuclear capacity. The Coal Retires Portfolio replaces all of the pulverized coal capacity and builds for load growth. The quantity of MWs needed plus the addition of a full nuclear unit make the Coal Retires Portfolio the most sensitive portfolio to changes in capital costs.

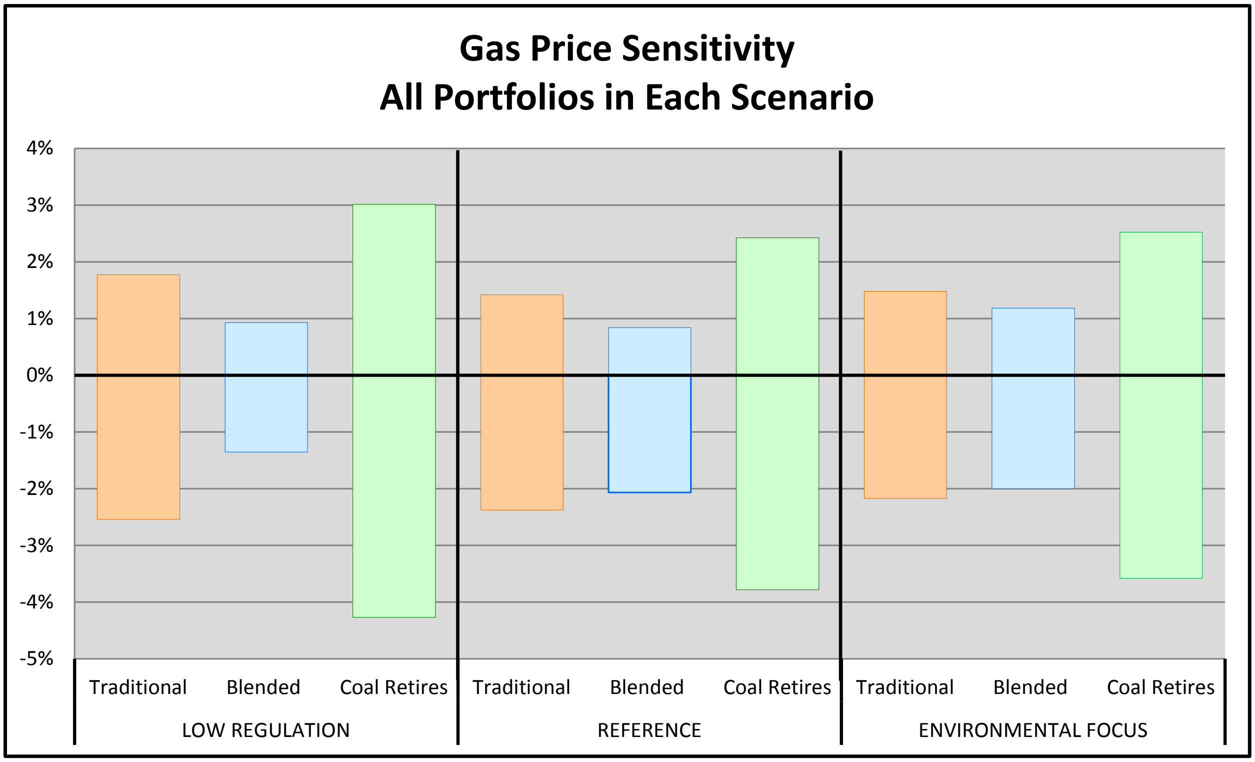
Gas Price Sensitivity

Gas prices were developed based on the supply and demand outlook for natural gas under the assumptions for each scenario. High and low sensitivities were conducted using the base price +15% and -21%, as discussed in more detail in Chapter 5. Table 8-I defines the indicative gas price sensitivities evaluated. Figure 8-L shows how each portfolio's PVRR responds to gas price changes.

Table 8-I: Gas Price Sensitivities

	SCENARIOS		
	Low Regulation	Reference	Environmental Focus
High Senstivity	$6-15/mmBtu	$5-14/mmBtu	$6-13/mmBtu
Base Assumption	$5-13/mmBtu	$5-12/mmBtu	$5-11/mmBtu
Low Sensitivity	$4-10 /mmBtu	$4-10/mmBtu	$4-9/mmBtu

Figure 8-L: Gas Price Sensitivity



Portfolios that include more gas-fired generation are more sensitive to changes in gas price, but this is mitigated to the degree that a portfolio has the flexibility to re-dispatch in response to changes in gas prices. The Coal Retires Portfolio is most sensitive to changes in gas prices due to the significant amount of gas-fired generation that is built to replace the retired Gibson and Cayuga units. The Traditional Portfolio builds primarily gas fired generation and this manifests itself in this portfolio being second most sensitive. The Blended Approach Portfolio enjoys the diversity of its generation mix in this sensitivity. With its mix of nuclear, coal, gas, renewable and EE, this portfolio is the least sensitivity to changes in gas prices.

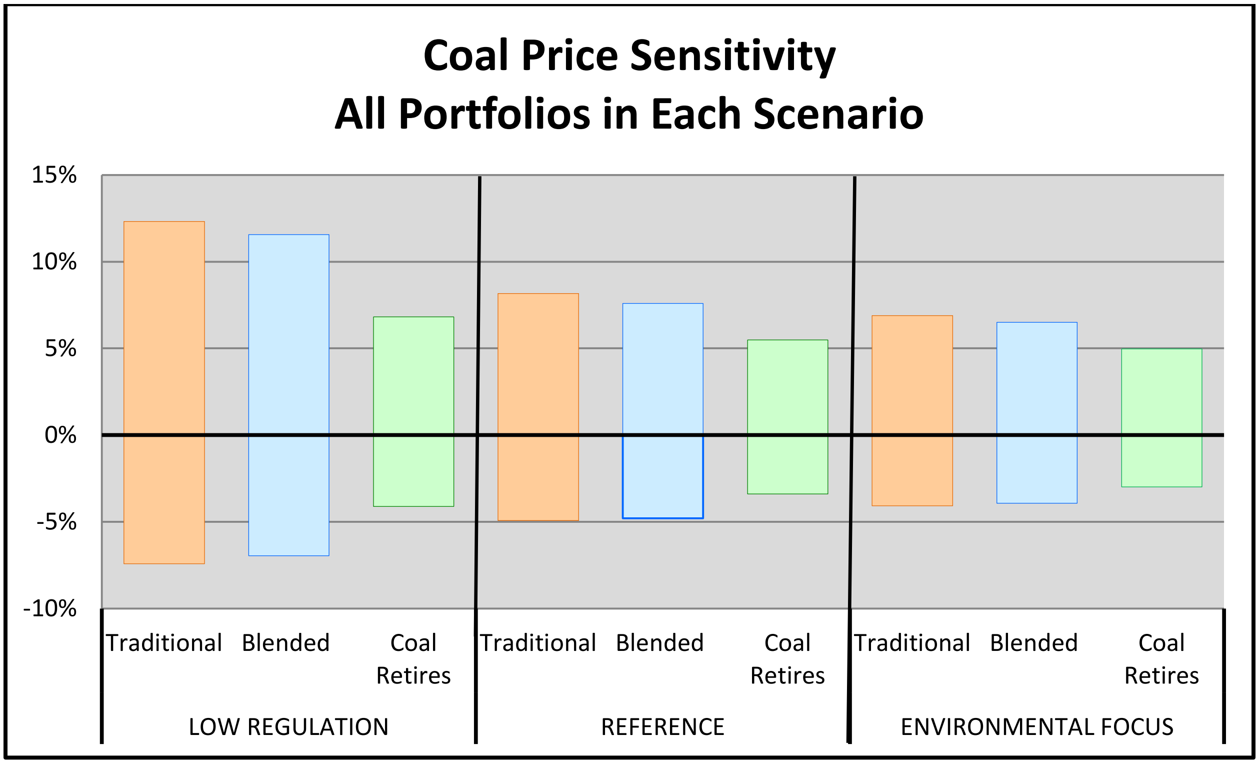
Coal Price Sensitivity

Coal prices were developed for each scenario based on the coal supply and demand given the particular assumptions for each scenario. High and low sensitivities were conducted using the base forecast +25% and -15%, as discussed in more detail in Chapter 5. Table 8-J defines the indicative coal price sensitivities evaluated. Figure 8-M shows how each portfolio's PVRR responds to coal price changes.

Table 8-J: Coal Price Sensitivities

	SCENARIOS		
	Low Regulation	**Reference**	**Environmental Focus**
High Senstivity	$3-6/mmBtu	$4-6/mmBtu	$4-5/mmBtu
Base Assumption	$3-5/mmBtu	$3-5/mmBtu	$3-4/mmBtu
Low Sensitivity	$2-4/mmBtu	$2-4/mmBtu	$2-3/mmBtu

Figure 8-M: Coal Price Sensitivity



Given the limited number of coal retirements and lack of nuclear capacity in the Traditional Portfolio, this portfolio has the most coal generating capacity and so experiences the greatest sensitivity to changes in coal prices. On the other end of the spectrum, the Coal Retires Portfolio has the least amount of coal-based energy due to its retirements, nuclear capacity, and higher renewable energy and EE; as a result, it has the least sensitivity to coal price changes. The Blended Approach Portfolio is closer to the Traditional Portfolio in terms of coal price sensitivity due to the continued operation of the large coal generating units.

8. <u>Sensitivity Conclusions</u>

Many of the insights gained by sensitivity analysis are covered in the scenario analysis. Portfolios optimized for different futures have different attributes and these were seen in the specific sensitivities. The coal-heavy, low renewable and EE Traditional Portfolio has the greatest sensitivity to CO_2 and coal prices. The low coal, high renewable and EE Coal Retires Portfolio has the greatest sensitivity to capital cost and gas prices. In most sensitivities, the Blended Approach Portfolio is the second most sensitive portfolio and it is the least sensitive to gas prices sue to its diverse generation mix.

9. Risk Management & Decision Making

The objective of the IRP is to produce a robust portfolio that meets the load obligation while minimizing the PVRR, subject to laws and regulations, reliability and adequacy requirements, operationally feasibility.

The IRP is a 20 year plan that is updated every two years. As decisions are made in the near term, additional analysis is conducted using the best available information at that time. The strategic flexibility of planning for the long term and then evaluating near term decisions provides context to the overall execution of a resource portfolio.

In terms of selecting a plan, cost under a range of probability assumptions is an important consideration as well as the performance of each portfolio under a range of sensitivities. Additionally, the difference between the portfolios in the next 5 years is particularly important at this time due to the number of environmental regulations that should be clarified in this time period. Fortunately, the three portfolios are very similar in the near term with the primary difference being the EE assumptions and the conversion of Wabash River 6 to natural gas. Once the regulations have been finalized, a more informed decision can be made for future resources.

10. Resource Plan Selection

Based on the frequency when the Blended Approach Portfolio is the least cost portfolio, the lack of times when it is the highest cost portfolio and its performance in the sensitivity analysis, the Blended Approach Portfolio was selected as the IRP Portfolio. The Portfolio includes diversified mix of new CT, CC, and nuclear capacity with significant EE and renewable contributions to replace several coal units and meet expected load growth. See Tables 8-K through 8-M for additional details.

Short Term

Over the next five years, the Plan retires Wabash River 2-5 and several small oil CTs. New resources come from converting Wabash River 6 to natural gas, plus enough additional EE and renewables capacity avoids the need for new traditional generation.

Long Term

The retirement of older coal and oil fired CT capacity sets the stage to respond to emerging environmental regulations. Future decisions to retire or control units will be made at the appropriate time using the best available information available then. In two years, the IRP process will be repeated and consider updated short term and long term forecasts.

Table 8-K: Integrated Resource Plan

DUKE ENERGY INDIANA INTEGRATED RESOURCE PLAN BLENDED APPROACH PORTFOLIO AND RECOMMENDED PLAN (2013-2033)						
Year	Retirements	Additions	Renewables (Nameplate MW) [1]			Notable, Near-term Environmental Control Upgrades [2]
			Wind	Solar	Biomass	
2013						
2014						Gibson 4 Precipitator Refurb
2015	Wabash River 2-5 (350 MW)					Cayuga 1&2 SCRs Gibson 3 Precipitator Refurb Gibson 5 Precipitator Refurb
2016	Wabash River 6 Coal (318 MW)	Wabash River 6 NG Conversion (318 MW)				Gibson 5 FGD Refurb
2017						
2018	Connersville 1&2 CT (86 MW) Mi-Wabash 1-3,5-6 CT (80 MW)			60	4	
2019	Gallagher 2&4 (280 MW)	CT 200 MW	50	30		
2020		CT 200 MW	50	20	2	
2021			50	30		
2022			50	20	2	
2023		CT 200 MW		30		
2024			50	30	2	
2025		CT 200 MW	50	40	2	
2026			250	70		
2027		CC 340 MW			2	
2028						
2029						
2030		CC 340 MW				
2031	Wabash River 6 NG (318 MW)	Nuclear 280 MW	250			
2032			600			
2033			600			
Total MW	1432	2078	2000	330	14	

1: Wind and solar MW represent nameplate capacity.

2: Additional likely or potential control requirements include additives for mercury control, ash system modifications, landfill requirements, and intake structure modifications in the 2015 -2023 time frame.

Table 8-L IRP Plan Emission Control Equipment Installation Dates

	Mercury				SO2		NO_x		Water		CCR
Unit	CEMS/ Traps	Dampers	Additives	Precip Refurb	FGD Refurb	DBA	SCR	SNCR	Intake Mods	Water Treatment	Ash Handling/ Landfill
Cayuga 1	2015						2015		2020	2019	2019
Cayuga 2	2015						2016		2020	2019	2019
Gallagher 2	2015										
Gallagher 4	2015										
Gibson 1			2015			2020			2018	2019	2019
Gibson 2			2015			2020			2018	2019	2019
Gibson 3			2015	2015		2020			2018	2019	2019
Gibson 4			2015	2014		2020			2018	2019	2019
Gibson 5		2015	2015	2015	2016	2020	2020 [1]		2018	2019	2019

Note 1: Gibson 5 existing SCR upgrades required

Table 8-M: Load, Capacity and Reserves Table[14]

Summer Projections of Load, Capacity, and Reserves
for Duke Energy Indiana 2013 IRP

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Load Forecast																					
1 DEI System Peak	6,542	6,686	6,555	6,746	6,876	6,998	7,083	7,203	7,301	7,399	7,499	7,569	7,699	7,798	7,891	7,963	8,061	8,195	8,297	8,403	8,485
Reductions to Load Forecast																					
2 New Conservation Programs	(26)	(77)	(140)	(213)	(299)	(392)	(496)	(551)	(560)	(567)	(575)	(549)	(589)	(597)	(604)	(577)	(586)	(593)	(635)	(641)	(615)
3 Demand Response Programs	(502)	(528)	(549)	(568)	(577)	(587)	(587)	(587)	(587)	(587)	(587)	(587)	(587)	(587)	(587)	(587)	(587)	(587)	(587)	(587)	(587)
4 Adjusted Duke System Peak	**6,015**	**6,081**	**5,866**	**5,965**	**5,999**	**6,019**	**6,000**	**6,065**	**6,154**	**6,246**	**6,338**	**6,433**	**6,523**	**6,615**	**6,700**	**6,799**	**6,888**	**7,015**	**7,075**	**7,175**	**7,284**
Cumulative System Capacity																					
4 Generating Capacity	7,706	7,706	7,356	7,040	7,040	7,040	6,874	6,594	6,594	6,594	6,594	6,594	6,594	6,594	6,594	6,594	6,594	6,594	6,594	6,276	6,276
5 Capacity Additions	0	0	0	318	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 Capacity Derates	0	0	(316)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Capacity Retirements	0	(350)	0	(318)	0	(166)	(280)	0	0	0	0	0	0	0	0	0	0	0	(318)	0	0
8 Cumulative Generating Capacity	7,706	7,356	7,040	7,040	7,040	6,874	6,594	6,594	6,594	6,594	6,594	6,594	6,594	6,594	6,594	6,594	6,594	6,594	6,276	6,276	6,276
Purchase Contracts																					
9 Cumulative Purchase Contracts	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	0	0	0	0	0	0
10 Behind the Meter Generation	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
12 Cumulative Future Resource Additions																					
Base Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	280	280	280
Peaking/Intermediate	0	0	0	0	0	0	200	400	400	400	600	600	800	800	1,140	1,140	1,140	1,480	1,480	1,480	1,490
Renewables	0	0	0	0	0	29	46	61	78	93	106	124	148	200	202	202	202	202	224	278	331
13 Cumulative Production Capacity	**7,733**	**7,383**	**7,067**	**7,067**	**7,067**	**6,930**	**6,867**	**7,082**	**7,099**	**7,114**	**7,327**	**7,345**	**7,569**	**7,621**	**7,963**	**7,954**	**7,954**	**8,294**	**8,278**	**8,332**	**8,395**
Reserves																					
14 Generating Reserves	1,719	1,302	1,201	1,102	1,068	911	867	1,017	945	869	989	912	1,046	1,006	1,263	1,155	1,066	1,279	1,203	1,158	1,112
15 % Reserve Margin	**28.6%**	**21.4%**	**20.5%**	**18.5%**	**17.8%**	**15.1%**	**14.4%**	**16.8%**	**15.3%**	**13.9%**	**15.6%**	**14.2%**	**16.0%**	**15.2%**	**18.9%**	**17.0%**	**15.5%**	**18.2%**	**17.0%**	**16.1%**	**15.3%**
16 % Capacity Margin	22.2%	17.6%	17.0%	15.6%	15.1%	13.1%	12.6%	14.4%	13.3%	12.2%	13.5%	12.4%	13.8%	13.2%	15.9%	14.5%	13.4%	15.4%	14.5%	13.9%	13.2%

[14] The 316 MW derate in 2015 (row 6) reflects expiration of the 310MW Gibson 5 back-up to IMPA and WVPA 12/31/14 and 6MW Cayuga derate for SCRs.

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The Duke Energy Indiana 2013 Integrated Resource Plan

November 1, 2013

Appendix A: Supply Side Screening Curves/ Resource Data

APPENDIX A – Table of Contents

1. Supply-Side Screening Curves

The following pages contain the screening curves and associated data discussed in Chapter 5 of this filing.

Duke Energy Indiana and its consultants consider cost estimates to be confidential and competitive information. The redacted information will be made available to appropriate parties upon execution of appropriate confidentiality agreements or protective orders. Please contact Beth Herriman at (317) 838-1254 for more information.

Figure A-1 No CO_2

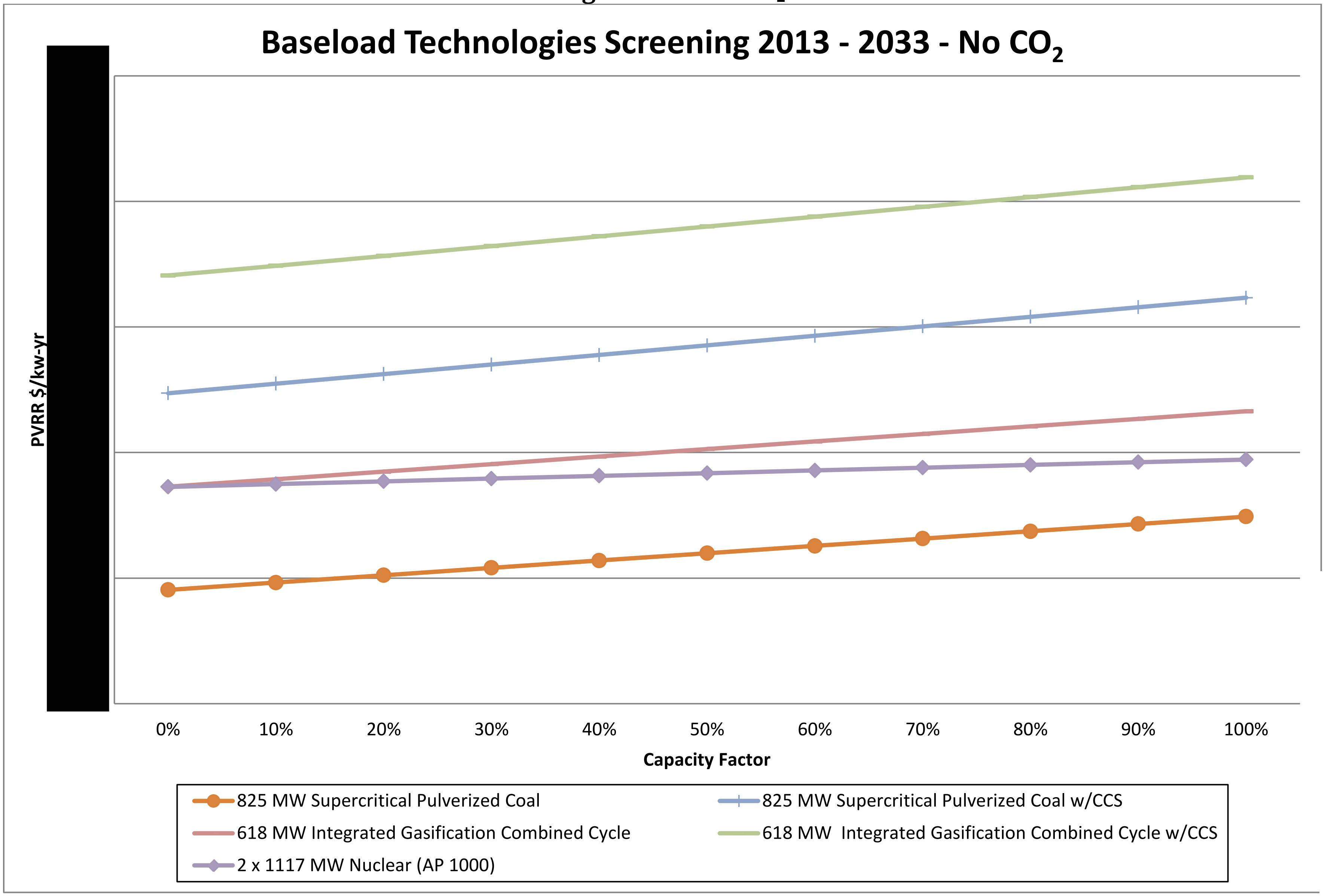
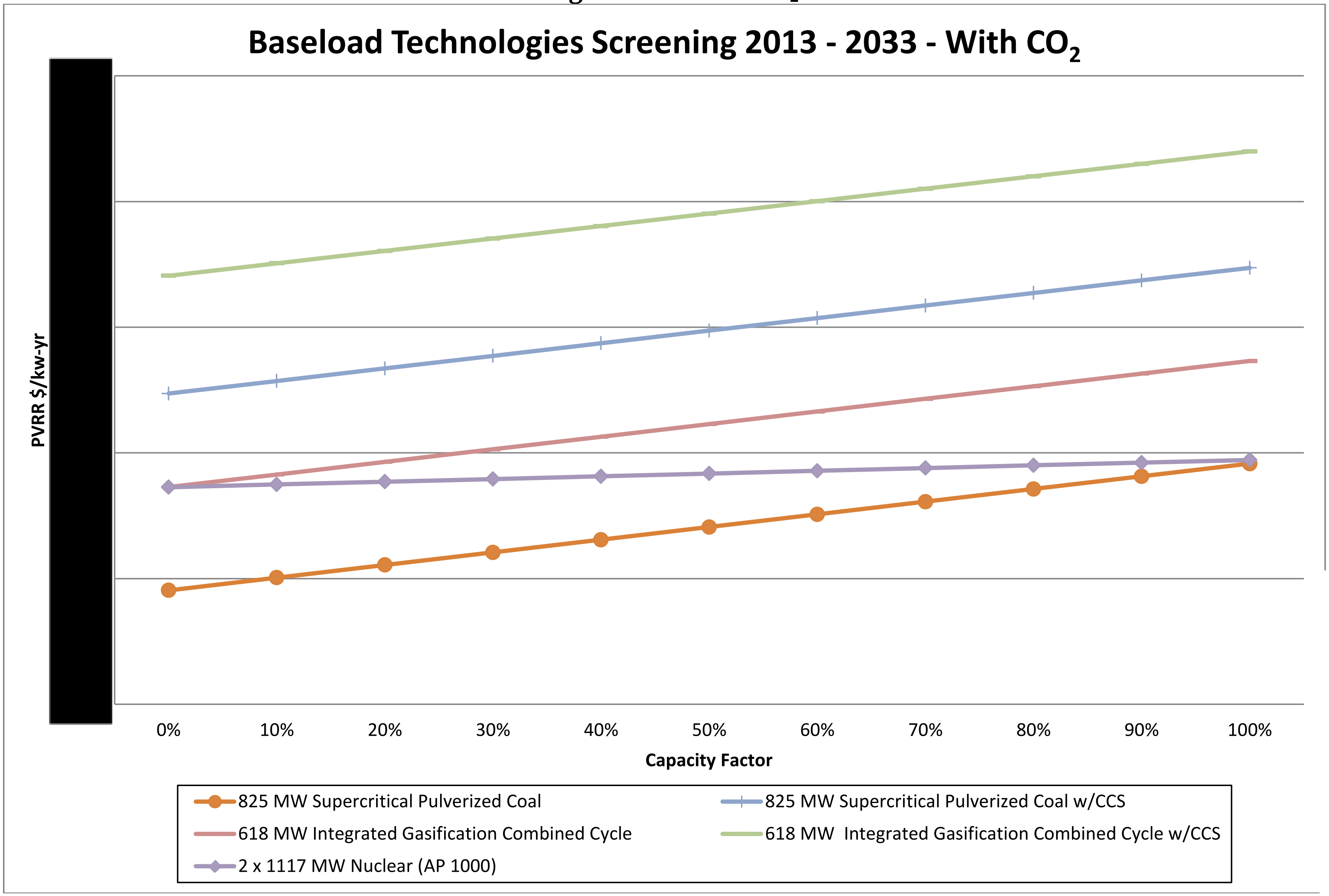


Figure A-1 With CO_2



CONFIDENTIAL and PROPRIETARY
NOT FOR PUBLIC ACCESS

Figure A-2 No CO_2

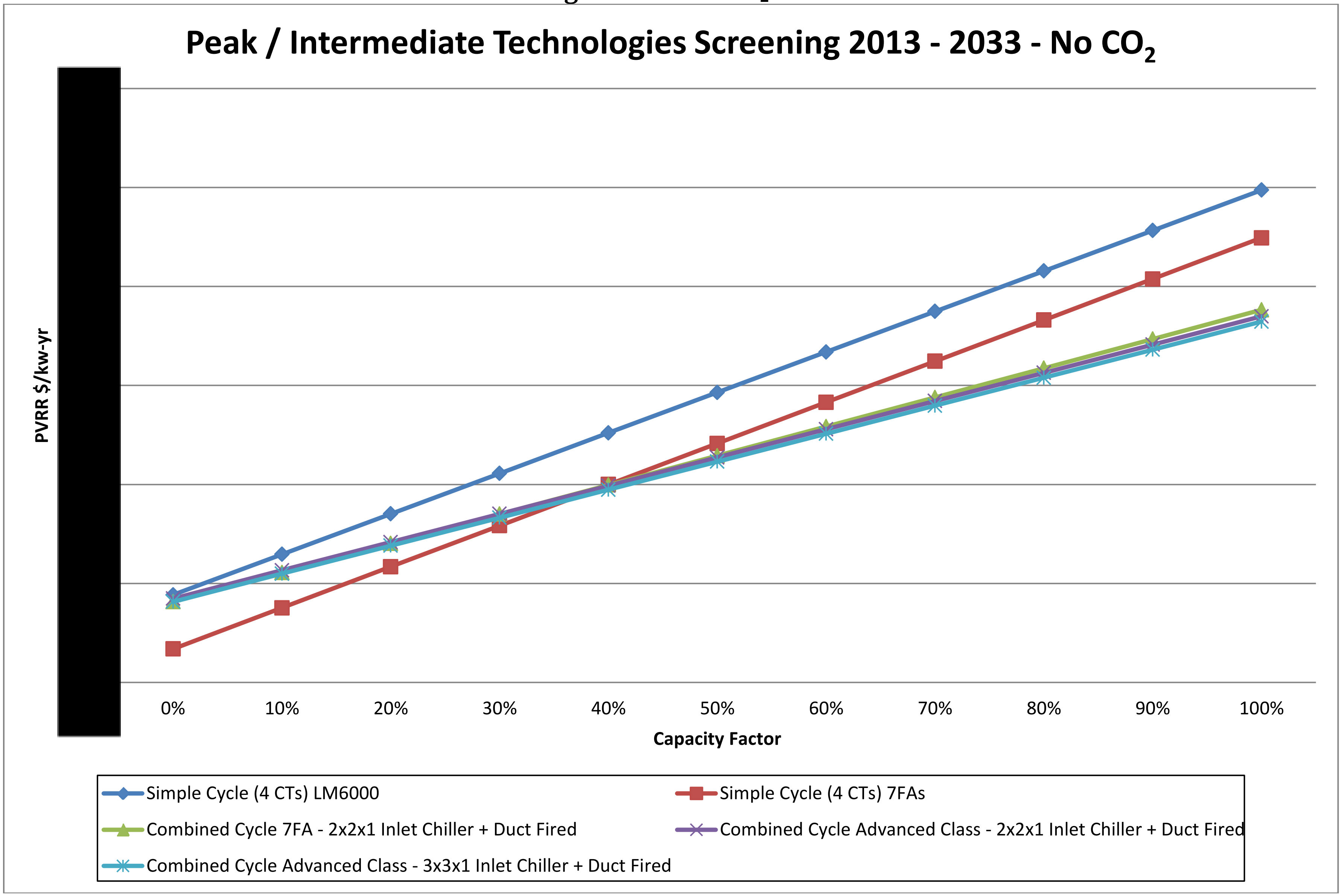


Figure A-2 With CO_2

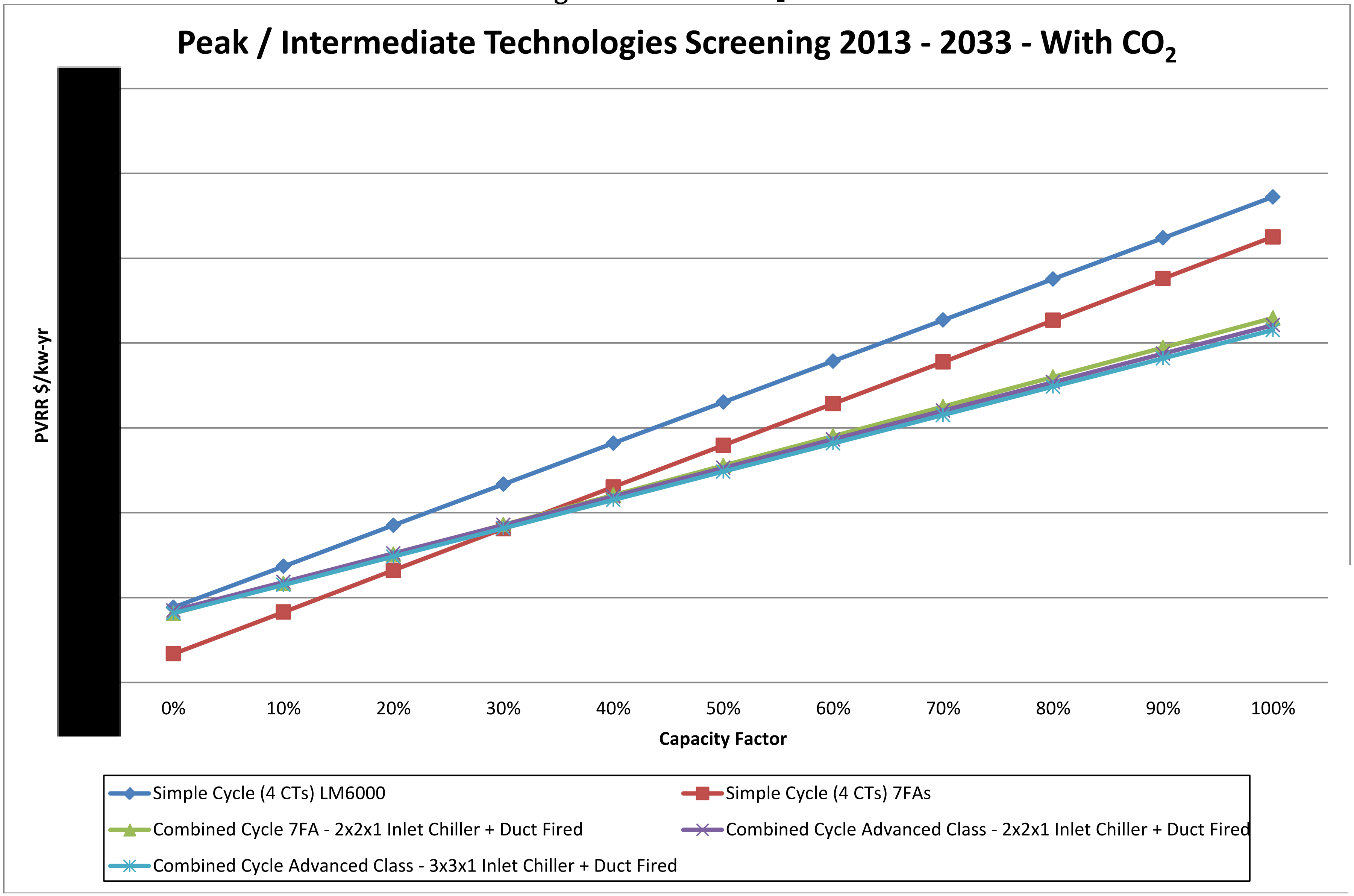


Figure A-3

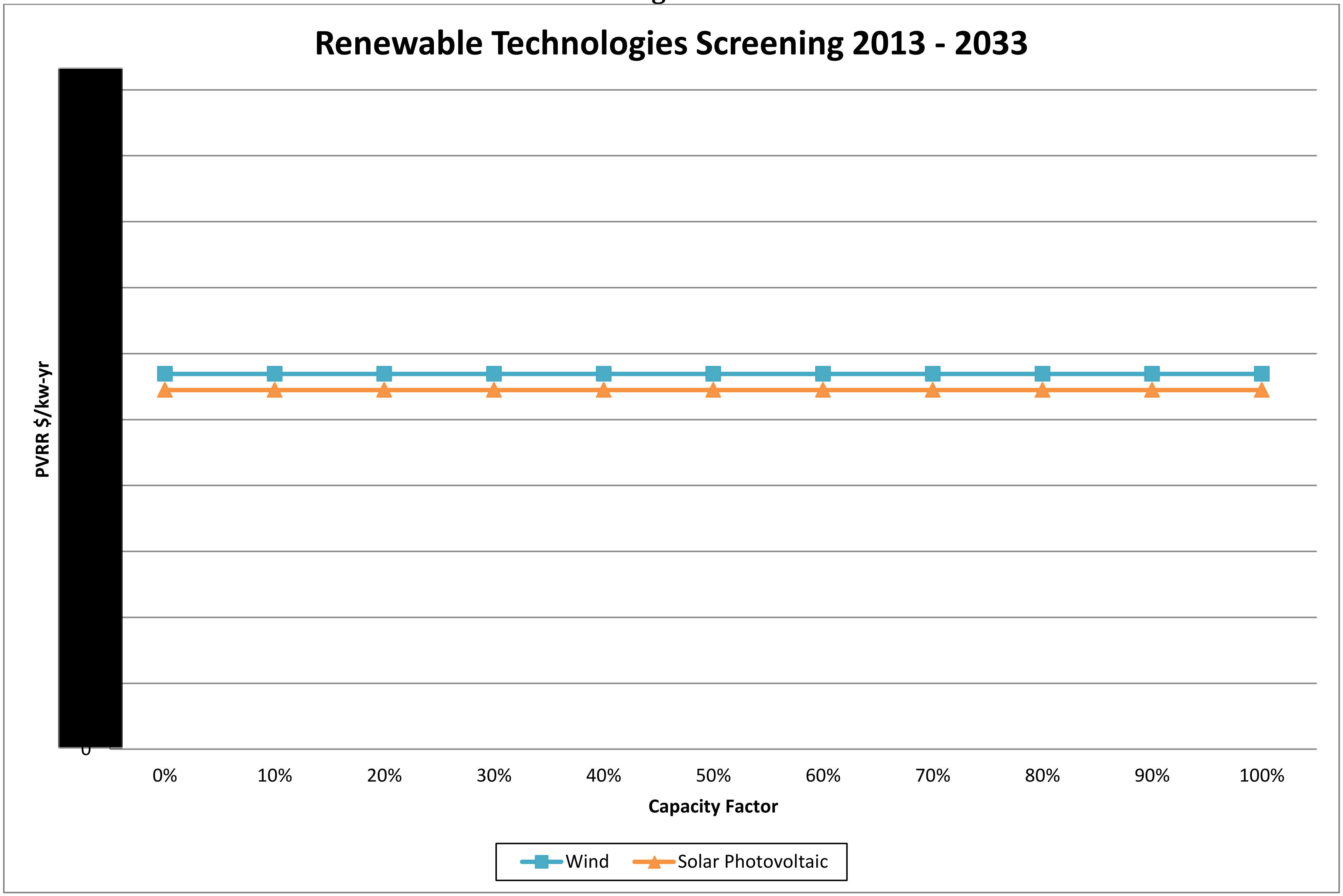

Renewable Technologies Screening 2013 - 2033
PVRR $/kw-yr
[redacted]
0
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Capacity Factor
Wind
Solar Photovoltaic

Figure A-4 (No CO_2)
Supply Side Technology Information – No CO_2

Discount Rate	[redacted]
Coal Price Escalation Rate	
Gas Price Escalation Rate	
EA Price Escalation Rate	
FOM and VOM Escalation Rate (%)	
Confidential business information	

		Plant A	Plant B	Plant C	Plant D	Plant E	Plant F	Plant G	Plant H	Plant I	Plant J	Plant K	Plant L
Technology Description		Simple Cycle (4 CTs) LM6000	Simple Cycle (4 CTs) 7FAs	Combined Cycle 7FA - 2x2x1 Inlet Chiller + Duct Fired	Combined Cycle Advanced Class - 2x2x1 Inlet Chiller + Duct Fired	Combined Cycle Advanced Class - 3x3x1 Inlet Chiller + Duct Fired	825 MW Supercritical Pulverized Coal	825 MW Supercritical Pulverized Coal w/CCS 800#/nMWHR	618 MW IGCC	618 MW w/CCS 800#/nMWHR IGCC	2 x 1117 MW Nuclear (AP 1000)	Wind	Solar Photovoltaic
Book Life/Tax Life	Years	[redacted]											
Nominal Unit Size at 100% Load	MW												
Total Plant Cost for Screening (2013 completion date)	$/kW												
Total Plant Cost for Screening (incl AFUDC-2013 completion date)	$/kW												
Total Plant Cost for Screening (incl AFUDC-2013 completion date)	MM$												
Average Annual Heat Rate	Btu/kWh												
VOM in 2013$	$/MWh												
FOM in 2013$	$/kW-yr												
Equivalent Planned Outage Rate	%												
Equivalent Unplanned Outage Rate	%												
Equivalent Availability	%												
SO_2 Emission Rate	Lbm/MMbtu												
NO_x Emission Rate	Lbm/MMBtu												
Hg Emission Rate	Lbm/Tbtu												
CO_2 Emission Rate	Lbm/MMBtu												

Note:
The values shown above are relative for planning purposes. Absolute values may vary considerably depending on many factors, including but not limited to: unit size, seasonal deratings, specific site requirements, and equipment vendor competition.

Figure A-4 (With CO_2)
Supply Side Technology Information – With CO_2

Discount Rate	[redacted]
Coal Price Escalation Rate	
Gas Price Escalation Rate	
EA Price Escalation Rate	
FOM and VOM Escalation Rate (%)	
Confidential business information	

		Plant A	Plant B	Plant C	Plant D	Plant E	Plant F	Plant G	Plant H	Plant I	Plant J	Plant K	Plant L
Technology Description		Simple Cycle (4 CTs) LM6000	Simple Cycle (4 CTs) 7FAs	Combined Cycle 7FA - 2x2x1 Inlet Chiller + Duct Fired	Combined Cycle Advanced Class - 2x2x1 Inlet Chiller + Duct Fired	Combined Cycle Advanced Class - 3x3x1 Inlet Chiller + Duct Fired	825 MW Supercritical Pulverized Coal	825 MW Supercritical Pulverized Coal w/CCS 800#/nMWHR	618 MW IGCC	618 MW w/CCS 800#/nMWHR IGCC	2 x 1117 MW Nuclear (AP 1000)	Wind	Solar Photovoltaic
Book Life/Tax Life	Years	[redacted]											
Nominal Unit Size at 100% Load	MW												
Total Plant Cost for Screening (2013 completion date)	$/kW												
Total Plant Cost for Screening (incl AFUDC-2013 completion date)	$/kW												
Total Plant Cost for Screening (incl AFUDC-2013 completion date)	MM$												
Average Annual Heat Rate	Btu/kWh												
VOM in 2013$	$/MWh												
FOM in 2013$	$/kW-yr												
Equivalent Planned Outage Rate	%												
Equivalent Unplanned Outage Rate	%												
Equivalent Availability	%												
SO_2 Emission Rate	Lbm/MMbtu												
NO_x Emission Rate	Lbm/MMBtu												
Hg Emission Rate	Lbm/Tbtu												
CO_2 Emission Rate	Lbm/MMBtu												

Note:
The values shown above are relative for planning purposes. Absolute values may vary considerably depending on many factors, including but not limited to: unit size, seasonal deratings, specific site requirements, and equipment vendor competition.

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2. Fuel and O&M Costs

The fuel costs and annual fixed and variable O&M costs for each unit (both existing and new) in the IRP are voluminous. Duke Energy Indiana also considers them to be trade secrets and confidential and competitive information. They will be made available to appropriate parties for viewing at Duke Energy Indiana offices during normal business hours upon execution of an appropriate confidentiality agreement or protective order. Please contact Beth Herriman at (317) 838-1254 for more information.

3. Air and Waste Emissions, Water Consumption and Discharge

The table on the following page represents the total air emissions projections for Duke Energy Indiana's existing and planned units for this IRP. This table contains total system tons of NO_x, SO_x and CO_2 emissions for the selected case in this IRP. Solid waste disposal and hazardous waste and subsequent disposal costs are included in the analysis, but the model does not quantify these waste streams in its output. Please contact Beth Herriman at (317) 838-1254 for more information.

Figure A-5 (System)

Air Emissions and Water Usage - System

					Water	
	CO_2	NO_x	SO_2	Mercury	Consumed	Discharged
	kTons	kTons	kTons	Pounds	Mgal	Mgal
2013	[redacted]					
2014						
2015						
2016						
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						
2025						
2026						
2027						
2028						
2029						
2030						
2031						
2032						
2033						

Figure A-5 (New CTs)

Air Emissions and Water Usage - New CTs

	CO_2 kTons	NO_x kTons	SO_2 kTons	Mercury Pounds	Water Consumed Mgal	Water Discharged Mgal
2013	[redacted]					
2014						
2015						
2016						
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						
2025						
2026						
2027						
2028						
2029						
2030						
2031						
2032						
2033						

Figure A-5 (New CC)

Air Emissions and Water Usage - New CC

	CO_2 kTons	NO_x kTons	SO_2 kTons	Mercury Pounds	Water Consumed Mgal	Water Discharged Mgal
2013	[redacted]					
2014						
2015						
2016						
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						
2025						
2026						
2027						
2028						
2029						
2030						
2031						
2032						
2033						

Figure A-5 (New Nuclear)

Air Emissions and Water Usage - New Nuclear

	CO_2	NO_x	SO_2	Mercury	Water Consumed	Water Discharged
	kTons	kTons	kTons	Pounds	Mgal	Mgal
2013	[redacted]					
2014						
2015						
2016						
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						
2025						
2026						
2027						
2028						
2029						
2030						
2031						
2032						
2033						

Figure A-6

Approximate Fuel Storage Capacity

Generating Station	Coal Capacity (Tons)	Oil Capacity (Gallons)
Cayuga	800,000	302,555
Connersville	--	514,800
Edwardsport IGCC	450,000	
Gallagher	245,000	130,000
Gibson	2,275,000 w/two piles	520,000
Miami-Wabash	--	766,600
Noblesville	--	45,300
Wabash River	380,000	346,550

Figure A-7
Duke Energy Indiana
Summary of Long Term Power Purchase Agreements

Supplier	Type	Expiration Date	Summer MW	Winter MW	Notes
Benton County Wind Farm	Wind PPA	April-2028	9	9	8.9% capacity value used in 2013 IRP
City of Logansport	Unit Peaking	December-2018	8	8	Effective July 1, 2009, Duke Energy Indiana purchased all Logansport Unit #6 capacity from the City of Logansport. In summer 2011, the City notified Duke Energy Indiana that this unit was unavailable until further notice.

The Duke Energy Indiana
2013 Integrated Resource Plan

November 1, 2013

Appendix B:
Electric Load Forecast

APPENDIX B – Table of Contents

1. Load Forecast Dataset

The Load Forecast Dataset utilized in developing Duke Energy Indiana's 2013 IRP is voluminous in nature. This data will be made available to appropriate parties for viewing at Duke Energy Indiana offices during normal business hours upon execution of an appropriate confidentiality agreement or protective order. Please contact Beth Herriman at (317) 838-1254 for more information.

2. 2012 Hourly Load Data

The 2012 hourly load data for the Duke Energy Indiana system is contained on the following pages.

Month	Day	Year	Hr 1&13	Hr 2&14	Hr 3&15	Hr 4&16	Hr 5&17	Hr 6&18	Hr 7&19	Hr 8&20	Hr 9&21	Hr 10&22	Hr 11&23	Hr 12&24
1	1	2012	3,201	3,138	3,076	3,006	3,009	3,002	3,043	3,112	3,379	3,304	3,426	3,518
1	1	2012	3,585	3,510	3,486	3,391	3,538	3,999	4,160	4,161	4,192	4,009	3,950	3,604
1	2	2012	3,607	3,488	3,439	3,425	3,534	3,721	4,292	4,445	4,545	4,703	4,858	4,866
1	2	2012	4,883	4,876	4,813	4,659	4,664	5,042	5,208	5,214	5,120	4,999	4,680	4,522
1	3	2012	4,352	4,356	4,375	4,334	4,397	4,685	5,167	5,368	5,400	5,245	5,203	5,086
1	3	2012	5,086	5,032	4,929	4,831	4,773	5,033	5,279	5,303	5,226	5,178	4,930	4,720
1	4	2012	4,336	4,202	4,216	4,179	4,245	4,624	5,028	5,227	5,163	5,166	5,059	5,008
1	4	2012	4,796	4,755	4,600	4,526	4,588	4,751	4,940	4,951	4,856	4,751	4,526	4,246
1	5	2012	3,808	3,772	3,736	3,742	3,820	4,487	4,775	5,007	4,991	4,844	4,658	4,552
1	5	2012	4,450	4,388	4,376	4,329	4,257	4,425	4,749	4,730	4,702	4,549	4,383	4,194
1	6	2012	3,593	3,489	3,482	3,488	3,555	3,927	4,312	4,552	4,517	4,477	4,374	4,268
1	6	2012	4,228	4,164	4,063	4,213	4,154	4,249	4,411	4,412	4,345	4,204	3,961	3,640
1	7	2012	3,312	3,269	3,123	3,172	3,290	3,329	3,586	3,745	3,870	3,843	3,915	3,834
1	7	2012	3,745	3,670	3,573	3,767	3,952	4,133	4,332	4,291	4,212	4,235	4,146	3,670
1	8	2012	3,369	3,325	3,344	3,364	3,370	3,635	3,859	3,976	4,000	4,034	3,960	3,931
1	8	2012	3,828	3,748	3,779	3,716	4,049	4,226	4,437	4,349	4,342	4,276	4,122	4,004
1	9	2012	3,707	3,399	3,418	3,415	3,512	4,183	4,642	4,888	4,921	4,860	4,735	4,593
1	9	2012	4,512	4,490	4,406	4,355	4,317	4,455	4,755	4,742	4,665	4,543	4,367	4,213
1	10	2012	3,830	3,609	3,540	3,585	3,709	4,313	4,736	4,986	4,960	4,824	4,754	4,558
1	10	2012	4,539	4,459	4,389	4,307	4,268	4,366	4,612	4,639	4,552	4,494	4,255	3,851
1	11	2012	3,758	3,530	3,506	3,458	3,463	4,102	4,470	4,716	4,709	4,688	4,676	4,667
1	11	2012	4,647	4,635	4,589	4,583	4,526	4,653	4,768	4,714	4,633	4,475	4,295	3,848
1	12	2012	3,956	3,671	3,628	3,544	3,616	4,043	4,370	4,552	4,580	4,583	4,662	4,688
1	12	2012	4,747	4,790	4,799	4,886	4,960	5,222	5,405	5,439	5,421	5,273	5,123	4,996
1	13	2012	4,654	4,624	4,587	4,569	4,643	4,844	5,163	5,547	5,603	5,541	5,589	5,537
1	13	2012	5,469	5,449	5,355	5,292	5,294	5,350	5,457	5,411	5,284	5,156	4,933	4,686
1	14	2012	4,085	4,035	4,000	3,970	4,009	4,088	4,414	4,818	4,893	5,014	4,979	4,887
1	14	2012	4,743	4,638	4,587	4,572	4,585	4,666	4,839	4,954	4,863	4,739	4,609	4,535
1	15	2012	4,026	3,982	3,898	3,886	3,901	4,259	4,698	4,800	4,807	4,768	4,674	4,649
1	15	2012	4,516	4,440	4,224	4,204	4,275	4,464	4,646	4,660	4,739	4,615	4,562	4,404
1	16	2012	3,818	3,807	3,718	3,768	3,841	4,178	4,697	4,872	4,832	4,834	4,825	4,802
1	16	2012	4,769	4,748	4,688	4,622	4,579	4,699	4,740	4,693	4,586	4,407	4,209	3,783
1	17	2012	3,400	3,318	3,249	3,250	3,278	3,478	4,217	4,478	4,492	4,493	4,508	4,450
1	17	2012	4,498	4,544	4,582	4,660	4,754	4,887	4,993	5,003	4,950	4,878	4,651	4,159
1	18	2012	3,941	3,903	3,880	3,874	3,942	4,384	4,953	5,281	5,243	5,190	5,167	5,041
1	18	2012	5,021	4,935	4,871	4,800	4,792	4,909	5,167	5,195	5,208	5,035	4,762	4,609
1	19	2012	4,075	4,043	3,957	3,953	4,014	4,600	5,002	5,150	5,133	5,092	5,063	4,974
1	19	2012	4,909	4,932	4,883	4,886	4,990	5,172	5,262	5,227	5,205	5,191	4,992	4,694
1	20	2012	4,419	4,443	4,483	4,280	4,373	4,970	5,288	5,479	5,457	5,421	5,437	5,347
1	20	2012	5,201	5,170	5,085	5,014	5,033	5,107	5,291	5,202	5,109	4,958	4,751	4,394
1	21	2012	4,309	4,237	4,174	3,975	3,985	4,255	4,404	4,584	4,699	4,981	5,055	4,990
1	21	2012	4,937	4,836	4,753	4,732	4,759	4,865	5,017	4,960	4,912	4,810	4,648	4,291
1	22	2012	3,959	3,827	3,749	3,793	3,765	3,964	4,041	4,249	4,306	4,578	4,589	4,620
1	22	2012	4,566	4,564	4,525	4,471	4,499	4,584	4,717	4,667	4,572	4,342	4,153	4,014
1	23	2012	3,430	3,313	3,255	3,254	3,327	4,014	4,375	4,624	4,561	4,543	4,680	4,685
1	23	2012	4,683	4,720	4,797	4,770	4,770	4,884	5,047	5,008	4,935	4,682	4,466	4,320
1	24	2012	3,738	3,645	3,642	3,627	3,745	4,391	4,718	4,947	4,950	4,863	4,898	4,889
1	24	2012	4,856	4,825	4,726	4,682	4,692	4,749	4,965	4,966	4,904	4,726	4,549	4,384
1	25	2012	3,766	3,711	3,746	3,710	3,826	4,511	4,834	5,081	5,056	4,998	4,964	4,940
1	25	2012	4,913	4,881	4,774	4,704	4,759	4,863	5,029	5,000	4,947	4,765	4,567	4,386
1	26	2012	3,783	3,702	3,579	3,643	3,659	4,257	4,570	4,758	4,770	4,730	4,722	4,705
1	26	2012	4,643	4,620	4,539	4,461	4,519	4,659	4,804	4,730	4,694	4,641	4,410	4,235
1	27	2012	3,859	3,787	3,764	3,717	3,763	4,239	4,613	4,849	4,775	4,795	4,764	4,754
1	27	2012	4,695	4,654	4,513	4,404	4,392	4,354	4,621	4,642	4,590	4,420	4,300	4,180
1	28	2012	4,059	3,895	3,850	3,860	3,866	4,059	4,198	4,365	4,474	4,484	4,493	4,407
1	28	2012	4,416	4,284	4,219	4,177	4,176	4,291	4,469	4,533	4,524	4,439	4,318	4,202
1	29	2012	3,800	3,700	3,656	3,631	3,681	3,940	4,110	4,238	4,264	4,241	4,303	4,259
1	29	2012	4,232	4,209	4,149	4,143	4,171	4,253	4,538	4,581	4,617	4,491	4,374	4,334
1	30	2012	3,836	3,746	3,721	3,748	3,850	4,524	4,818	5,069	5,077	5,052	5,023	4,886
1	30	2012	4,758	4,598	4,527	4,363	4,311	4,372	4,605	4,671	4,594	4,494	4,257	4,101
1	31	2012	3,566	3,396	3,314	3,297	3,366	4,057	4,419	4,610	4,536	4,498	4,457	4,384
1	31	2012	4,394	4,337	4,302	4,250	4,287	4,363	4,479	4,521	4,473	4,321	4,040	3,648

Month	Day	Year	Hr 1&13	Hr 2&14	Hr 3&15	Hr 4&16	Hr 5&17	Hr 6&18	Hr 7&19	Hr 8&20	Hr 9&21	Hr 10&22	Hr 11&23	Hr 12&24
2	1	2012	3,235	3,219	3,217	3,189	3,173	3,887	4,148	4,439	4,316	4,305	4,303	4,289
2	1	2012	4,224	4,015	3,988	3,926	3,895	3,997	4,161	4,212	4,152	4,078	3,868	3,566
2	2	2012	3,162	3,164	3,159	3,206	3,306	3,982	4,306	4,463	4,453	4,396	4,352	4,225
2	2	2012	4,159	4,091	4,011	4,046	3,947	4,047	4,230	4,388	4,341	4,296	4,133	3,993
2	3	2012	3,434	3,404	3,361	3,372	3,482	3,908	4,456	4,711	4,693	4,587	4,532	4,394
2	3	2012	4,270	4,171	4,058	3,973	3,907	4,033	4,200	4,210	4,182	4,024	3,905	3,571
2	4	2012	3,137	3,061	3,060	3,042	3,067	3,169	3,793	3,981	4,083	4,192	4,275	4,290
2	4	2012	4,226	4,226	4,148	4,115	4,139	4,197	4,227	4,123	4,105	3,996	3,888	3,369
2	5	2012	3,184	3,155	3,084	3,066	3,104	3,360	3,705	3,871	3,937	4,041	4,032	3,986
2	5	2012	3,937	3,882	3,778	3,804	3,731	3,813	3,964	4,022	4,008	3,964	3,996	3,726
2	6	2012	3,365	3,350	3,373	3,375	3,554	4,256	4,569	4,838	4,763	4,697	4,599	4,482
2	6	2012	4,197	4,229	4,225	4,166	4,162	4,244	4,469	4,576	4,549	4,419	4,277	4,134
2	7	2012	3,566	3,536	3,494	3,499	3,598	4,211	4,554	4,755	4,780	4,728	4,706	4,676
2	7	2012	4,608	4,543	4,448	4,440	4,429	4,533	4,687	4,715	4,725	4,536	4,317	4,173
2	8	2012	3,581	3,546	3,485	3,512	3,557	4,214	4,562	4,822	4,748	4,744	4,775	4,740
2	8	2012	4,706	4,703	4,645	4,598	4,633	4,693	4,840	4,795	4,786	4,627	4,423	4,252
2	9	2012	3,677	3,599	3,586	3,604	3,653	4,317	4,654	4,747	4,694	4,690	4,682	4,616
2	9	2012	4,600	4,579	4,530	4,507	4,578	4,698	4,810	4,906	4,866	4,717	4,503	4,310
2	10	2012	3,931	3,898	3,827	3,837	3,887	4,325	4,692	4,948	4,905	4,843	4,938	4,820
2	10	2012	4,812	4,829	4,718	4,424	4,486	4,425	4,479	4,482	4,454	4,339	4,180	4,054
2	11	2012	4,017	3,964	4,034	4,051	4,027	4,251	4,362	4,539	4,635	4,641	4,691	4,675
2	11	2012	4,604	4,525	4,449	4,412	4,448	4,510	4,769	4,847	4,770	4,676	4,611	4,490
2	12	2012	4,380	4,274	4,199	4,234	4,270	4,333	4,416	4,566	4,579	4,599	4,483	4,335
2	12	2012	4,240	4,162	4,034	3,923	3,879	3,969	4,183	4,337	4,362	4,222	4,155	4,082
2	13	2012	3,774	3,718	3,595	3,717	3,792	4,323	4,692	4,922	4,828	4,761	4,638	4,520
2	13	2012	4,485	4,493	4,454	4,439	4,408	4,426	4,626	4,698	4,635	4,453	4,315	4,099
2	14	2012	3,984	3,925	3,679	3,656	3,920	4,104	4,434	4,601	4,526	4,502	4,555	4,535
2	14	2012	4,522	4,454	4,509	4,495	4,478	4,495	4,639	4,609	4,602	4,474	4,174	4,019
2	15	2012	3,652	3,594	3,541	3,527	3,627	4,112	4,431	4,644	4,621	4,510	4,434	4,332
2	15	2012	4,372	4,390	4,351	4,333	4,348	4,450	4,539	4,535	4,478	4,361	4,147	3,917
2	16	2012	3,508	3,444	3,372	3,358	3,439	3,843	4,197	4,310	4,274	4,268	4,314	4,250
2	16	2012	4,205	4,230	4,164	4,225	4,237	4,217	4,376	4,564	4,472	4,355	4,156	3,773
2	17	2012	3,652	3,627	3,547	3,584	3,649	4,177	4,483	4,735	4,652	4,562	4,459	4,316
2	17	2012	4,207	4,177	4,067	3,939	3,934	3,944	4,103	4,177	4,173	4,023	3,864	3,565
2	18	2012	3,421	3,416	3,321	3,415	3,518	3,594	3,791	3,949	4,238	4,191	4,135	4,074
2	18	2012	3,991	3,974	3,847	3,788	3,786	3,826	4,000	4,136	4,084	4,146	3,997	3,684
2	19	2012	3,528	3,546	3,554	3,564	3,571	3,604	3,785	3,932	3,975	4,174	4,054	4,033
2	19	2012	3,948	3,643	3,640	3,671	3,869	3,984	4,157	4,319	4,283	4,207	4,139	3,831
2	20	2012	3,724	3,707	3,733	3,768	3,828	4,311	4,618	4,827	4,719	4,672	4,510	4,446
2	20	2012	4,379	4,263	4,127	4,082	4,047	4,147	4,386	4,507	4,477	4,410	4,190	4,010
2	21	2012	3,721	3,550	3,498	3,557	3,605	4,018	4,379	4,575	4,574	4,533	4,499	4,502
2	21	2012	4,452	4,435	4,397	4,359	4,334	4,318	4,424	4,502	4,427	4,265	4,061	3,878
2	22	2012	3,543	3,465	3,446	3,446	3,470	3,919	4,251	4,448	4,408	4,277	4,149	4,055
2	22	2012	4,031	4,047	3,942	3,981	3,952	3,969	4,154	4,198	4,210	4,140	3,950	3,666
2	23	2012	3,465	3,418	3,448	3,369	3,468	3,929	4,286	4,470	4,419	4,417	4,389	4,302
2	23	2012	4,223	4,207	4,139	4,091	4,084	4,154	4,271	4,325	4,283	4,141	3,943	3,558
2	24	2012	3,441	3,323	3,297	3,321	3,390	3,883	4,256	4,477	4,502	4,622	4,618	4,593
2	24	2012	4,593	4,539	4,522	4,458	4,447	4,471	4,497	4,535	4,517	4,430	4,242	3,869
2	25	2012	3,776	3,602	3,610	3,651	3,621	3,808	4,089	4,264	4,298	4,434	4,399	4,392
2	25	2012	4,284	4,188	4,082	4,018	3,973	4,023	4,176	4,308	4,290	4,233	4,105	4,021
2	26	2012	3,712	3,646	3,663	3,641	3,683	3,687	3,879	4,174	4,254	4,170	4,121	4,015
2	26	2012	3,978	3,879	3,795	3,724	3,634	3,716	3,932	4,147	4,116	4,023	3,702	3,629
2	27	2012	3,431	3,331	3,367	3,314	3,393	3,896	4,272	4,434	4,386	4,336	4,278	4,291
2	27	2012	4,251	4,211	4,148	4,088	4,038	4,051	4,214	4,437	4,422	4,318	4,187	3,795
2	28	2012	3,701	3,623	3,700	3,745	3,797	4,292	4,636	4,856	4,730	4,570	4,432	4,365
2	28	2012	4,333	4,258	4,209	4,157	4,177	4,246	4,386	4,384	4,387	4,241	4,033	3,631
2	29	2012	3,412	3,306	3,246	3,240	3,315	3,800	4,123	4,314	4,259	4,242	4,175	4,185
2	29	2012	4,162	4,137	4,102	4,069	3,997	3,963	4,062	4,214	4,138	4,025	3,810	3,323

Month	Day	Year	Hr 1&13	Hr 2&14	Hr 3&15	Hr 4&16	Hr 5&17	Hr 6&18	Hr 7&19	Hr 8&20	Hr 9&21	Hr 10&22	Hr 11&23	Hr 12&24
3	1	2012	3,062	3,002	3,014	3,027	3,181	3,594	3,853	4,089	4,068	4,050	4,044	3,990
3	1	2012	3,941	3,872	3,777	3,649	3,626	3,737	3,857	3,964	4,068	4,030	3,851	3,421
3	2	2012	3,276	3,211	3,210	3,196	3,284	3,661	3,997	4,151	4,081	4,019	4,042	4,024
3	2	2012	4,042	4,016	3,945	3,801	3,741	3,734	3,809	3,955	3,959	3,886	3,806	3,451
3	3	2012	3,394	3,229	3,217	3,238	3,333	3,472	3,902	4,026	4,164	4,256	4,404	4,387
3	3	2012	4,294	4,240	4,195	4,132	4,175	4,229	4,257	4,379	4,389	4,319	4,182	4,073
3	4	2012	3,717	3,658	3,594	3,526	3,578	3,677	3,965	3,995	4,086	4,167	4,111	4,203
3	4	2012	4,200	4,157	4,081	4,046	4,041	4,116	4,244	4,397	4,392	4,242	4,164	4,058
3	5	2012	3,765	3,762	3,798	3,795	3,903	4,337	4,606	4,839	4,905	4,852	4,778	4,767
3	5	2012	4,679	4,573	4,553	4,506	4,487	4,518	4,635	4,863	4,851	4,715	4,571	4,141
3	6	2012	4,031	4,004	3,893	3,973	4,045	4,449	4,735	4,847	4,732	4,691	4,579	4,523
3	6	2012	4,430	4,306	4,238	4,221	4,123	4,106	4,176	4,371	4,339	4,190	4,060	3,666
3	7	2012	3,440	3,279	3,261	3,203	3,482	3,636	4,081	4,278	4,246	4,177	4,263	4,250
3	7	2012	4,202	4,207	4,086	4,029	4,065	4,043	4,095	4,324	4,229	4,122	3,679	3,386
3	8	2012	3,298	3,170	3,046	3,021	3,091	3,232	3,784	4,065	4,125	4,154	4,211	4,195
3	8	2012	4,201	4,198	4,201	4,147	4,210	4,265	4,389	4,510	4,504	4,327	3,898	3,762
3	9	2012	3,585	3,521	3,490	3,531	3,676	4,011	4,483	4,563	4,542	4,512	4,540	4,468
3	9	2012	4,372	4,297	4,250	4,152	4,180	4,020	4,140	4,348	4,434	4,339	4,218	3,868
3	10	2012	3,719	3,609	3,580	3,576	3,658	3,823	3,733	3,986	4,018	3,905	3,935	3,880
3	10	2012	3,545	3,385	3,304	3,265	3,228	3,255	3,609	3,834	3,816	3,715	3,390	3,236
3	11	2012	3,133	3,020	3,062	3,036	3,081	3,239	3,397	3,662	3,624	3,573	3,486	3,322
3	11	2012	3,300	3,155	3,178	3,081	3,137	3,171	3,580	3,771	3,646	3,330	3,143	2,953
3	12	2012	2,850	2,803	2,884	2,923	3,291	3,834	4,191	4,250	4,243	4,271	4,246	4,276
3	12	2012	4,269	4,212	4,199	4,117	4,120	4,117	4,112	4,265	4,166	3,919	3,461	3,347
3	13	2012	3,155	3,148	3,072	3,110	3,249	3,765	4,060	4,106	4,123	4,178	4,153	4,171
3	13	2012	4,166	4,147	4,126	4,076	4,098	4,091	4,061	4,240	4,165	3,910	3,511	3,318
3	14	2012	3,148	3,019	2,963	2,972	3,192	3,812	4,148	4,130	4,118	4,129	4,210	4,176
3	14	2012	4,224	4,220	4,235	4,187	4,185	4,139	4,171	4,300	4,254	4,032	3,597	3,436
3	15	2012	3,198	3,082	2,967	2,946	3,120	3,758	4,031	4,044	4,094	4,131	4,162	4,204
3	15	2012	4,240	4,240	4,340	4,216	4,098	4,139	4,189	4,279	4,164	3,916	3,571	3,332
3	16	2012	3,103	3,050	2,985	2,983	3,097	3,709	4,046	4,018	4,051	4,105	4,155	4,141
3	16	2012	4,190	4,150	4,139	4,118	4,079	4,027	3,965	4,110	4,014	3,849	3,445	3,172
3	17	2012	3,003	2,891	2,913	2,854	2,909	2,979	3,354	3,506	3,704	3,788	3,839	3,819
3	17	2012	3,814	3,813	3,820	3,839	3,861	3,802	3,780	3,848	3,811	3,650	3,480	3,285
3	18	2012	3,034	2,856	2,791	2,753	2,740	2,800	2,917	3,291	3,424	3,582	3,719	3,707
3	18	2012	3,725	3,817	3,856	3,931	3,982	4,007	3,973	4,128	4,048	3,930	3,703	3,286
3	19	2012	3,082	2,999	3,040	2,984	3,161	3,794	4,141	4,058	4,102	4,228	4,248	4,379
3	19	2012	4,562	4,543	4,517	4,562	4,559	4,542	4,513	4,590	4,447	4,234	3,672	3,439
3	20	2012	3,277	3,183	3,074	3,153	3,319	3,870	4,071	4,103	4,149	4,246	4,356	4,488
3	20	2012	4,557	4,619	4,593	4,588	4,569	4,605	4,581	4,618	4,546	4,265	3,911	3,514
3	21	2012	3,363	3,291	3,195	3,237	3,342	3,927	4,233	4,220	4,285	4,413	4,491	4,699
3	21	2012	4,757	4,809	4,787	4,803	4,833	4,793	4,644	4,767	4,580	4,355	4,026	3,863
3	22	2012	3,447	3,335	3,301	3,337	3,405	3,963	4,214	4,295	4,366	4,509	4,606	4,707
3	22	2012	4,779	4,790	4,722	4,665	4,574	4,525	4,512	4,542	4,414	4,213	3,939	3,616
3	23	2012	3,385	3,286	3,242	3,263	3,394	3,947	4,143	4,196	4,297	4,356	4,379	4,369
3	23	2012	4,260	4,326	4,195	4,170	4,185	4,057	4,040	4,123	3,967	3,807	3,406	3,188
3	24	2012	3,082	2,999	2,952	2,873	2,946	3,061	3,253	3,527	3,651	3,723	3,764	3,741
3	24	2012	3,707	3,685	3,641	3,629	3,607	3,631	3,683	3,753	3,735	3,570	3,183	3,031
3	25	2012	2,932	2,809	2,794	2,802	2,775	2,900	2,988	3,360	3,397	3,540	3,546	3,576
3	25	2012	3,626	3,608	3,632	3,634	3,678	3,699	3,641	3,767	3,771	3,629	3,320	3,112
3	26	2012	3,048	2,942	2,891	2,827	2,948	3,590	3,825	3,856	3,899	3,869	3,867	3,920
3	26	2012	3,866	3,831	3,777	3,714	3,712	3,686	3,723	3,911	3,890	3,715	3,502	3,135
3	27	2012	3,078	2,979	2,978	3,045	3,291	3,845	4,073	4,100	3,989	3,959	3,886	3,872
3	27	2012	3,910	3,898	3,826	3,778	3,766	3,758	3,795	3,949	3,893	3,686	3,481	3,152
3	28	2012	3,039	2,894	2,891	2,906	3,124	3,615	3,832	3,862	3,921	3,980	4,033	4,069
3	28	2012	4,095	4,089	4,066	4,001	3,968	3,955	3,921	4,031	3,972	3,747	3,512	3,177
3	29	2012	2,983	2,906	2,895	2,900	3,034	3,646	3,896	3,914	3,956	4,005	3,993	3,976
3	29	2012	3,977	3,963	3,903	3,861	3,847	3,827	3,822	3,964	3,907	3,704	3,266	3,022
3	30	2012	2,999	2,959	2,935	3,025	3,178	3,635	3,836	3,849	3,909	3,944	3,963	3,995
3	30	2012	4,023	4,033	3,970	3,970	3,938	3,894	3,870	3,904	3,836	3,428	3,160	2,957
3	31	2012	2,804	2,748	2,662	2,670	2,737	2,931	3,080	3,462	3,584	3,692	3,743	3,633
3	31	2012	3,611	3,561	3,544	3,617	3,610	3,564	3,540	3,651	3,636	3,535	3,150	3,070

Month	Day	Year	Hr 1&13	Hr 2&14	Hr 3&15	Hr 4&16	Hr 5&17	Hr 6&18	Hr 7&19	Hr 8&20	Hr 9&21	Hr 10&22	Hr 11&23	Hr 12&24
4	1	2012	2,661	2,721	2,684	2,700	2,730	2,792	2,991	3,270	3,386	3,457	3,495	3,509
4	1	2012	3,482	3,407	3,460	3,508	3,569	3,583	3,625	3,696	3,715	3,564	3,223	3,088
4	2	2012	2,868	2,814	2,689	2,829	3,017	3,599	3,772	3,819	3,833	3,980	3,965	3,997
4	2	2012	3,947	3,936	3,894	3,936	3,949	3,941	3,895	4,018	3,952	3,772	3,328	3,146
4	3	2012	3,004	2,848	2,836	2,857	2,988	3,568	3,781	3,846	3,875	3,979	3,990	4,018
4	3	2012	4,047	4,227	4,295	4,322	4,295	4,274	4,220	4,373	4,256	4,020	3,537	3,201
4	4	2012	3,066	2,947	2,904	2,870	2,973	3,545	3,770	3,865	3,916	3,977	3,982	4,027
4	4	2012	4,067	4,004	4,001	3,959	3,886	3,841	3,840	3,936	3,947	3,731	3,333	3,063
4	5	2012	2,995	2,804	2,811	2,822	3,056	3,576	3,753	3,793	3,861	3,836	3,918	3,828
4	5	2012	3,934	3,883	3,789	3,723	3,737	3,741	3,717	3,800	3,834	3,633	3,182	3,031
4	6	2012	2,832	2,760	2,778	2,815	3,036	3,479	3,671	3,761	3,706	3,713	3,757	3,631
4	6	2012	3,572	3,593	3,411	3,348	3,413	3,339	3,382	3,547	3,436	3,454	3,103	2,926
4	7	2012	2,811	2,812	2,714	2,783	2,907	3,290	3,384	3,455	3,500	3,500	3,498	3,432
4	7	2012	3,387	3,299	3,334	3,324	3,297	3,326	3,343	3,468	3,462	3,334	2,940	2,734
4	8	2012	2,575	2,470	2,477	2,474	2,498	2,606	2,768	3,125	3,251	3,224	3,295	3,233
4	8	2012	3,194	3,128	3,130	3,138	3,171	3,183	3,266	3,390	3,481	3,361	3,016	2,842
4	9	2012	2,707	2,678	2,697	2,820	3,083	3,677	3,854	3,912	3,930	4,017	4,032	3,985
4	9	2012	3,980	3,943	3,912	3,844	3,820	3,798	3,818	3,899	3,870	3,693	3,261	3,154
4	10	2012	2,993	2,899	2,951	3,080	3,236	3,756	4,022	4,006	4,026	4,010	3,985	4,009
4	10	2012	4,014	3,913	3,914	3,884	3,861	3,882	3,912	4,058	4,056	3,852	3,393	3,358
4	11	2012	3,310	3,223	3,220	3,295	3,539	4,168	4,280	4,254	4,220	4,169	4,175	4,022
4	11	2012	4,064	4,028	3,941	3,917	3,906	3,887	3,869	3,991	4,021	3,807	3,432	3,344
4	12	2012	3,272	3,259	3,281	3,351	3,588	4,116	4,201	4,123	4,036	3,982	3,926	3,943
4	12	2012	3,917	3,938	3,893	3,846	3,756	3,782	3,766	3,933	3,954	3,743	3,334	3,151
4	13	2012	3,182	2,983	3,020	3,072	3,576	3,913	4,085	4,051	4,031	4,007	3,930	3,932
4	13	2012	3,968	3,936	3,818	3,789	3,734	3,725	3,728	3,766	3,797	3,618	3,439	3,097
4	14	2012	2,908	2,831	2,754	2,698	2,805	3,081	3,177	3,526	3,595	3,706	3,683	3,715
4	14	2012	3,658	3,643	3,641	3,616	3,529	3,580	3,544	3,644	3,602	3,519	3,094	2,913
4	15	2012	2,766	2,660	2,652	2,702	2,756	2,786	2,961	3,244	3,387	3,464	3,532	3,592
4	15	2012	3,595	3,548	3,595	3,648	3,724	3,757	3,744	3,843	3,894	3,691	3,275	3,174
4	16	2012	3,041	2,937	2,842	2,902	3,109	3,625	3,820	3,908	4,004	4,005	4,035	4,070
4	16	2012	4,056	4,042	3,975	3,935	3,940	3,878	3,855	3,960	3,864	3,677	3,279	3,133
4	17	2012	3,033	2,902	2,855	2,949	3,090	3,760	3,949	3,934	3,945	3,983	3,985	4,001
4	17	2012	3,976	3,953	3,896	3,859	3,845	3,796	3,827	3,911	3,923	3,737	3,244	3,194
4	18	2012	3,019	2,978	2,947	2,985	3,172	3,819	4,027	3,966	3,971	4,032	3,993	4,004
4	18	2012	4,018	3,990	3,963	3,921	3,880	3,913	3,846	3,896	3,959	3,730	3,488	3,105
4	19	2012	2,925	2,823	2,771	2,905	2,964	3,608	3,763	3,797	3,796	3,851	3,862	3,888
4	19	2012	3,926	3,908	3,881	3,894	3,985	3,956	3,889	4,014	3,994	3,805	3,319	3,180
4	20	2012	2,958	2,913	2,870	2,884	3,052	3,614	3,790	3,877	3,918	4,040	4,048	4,054
4	20	2012	4,036	4,004	3,947	3,921	3,876	3,796	3,724	3,780	3,756	3,486	3,133	2,990
4	21	2012	2,843	2,755	2,721	2,755	2,830	3,129	3,424	3,609	3,740	3,808	3,785	3,775
4	21	2012	3,674	3,560	3,560	3,567	3,539	3,487	3,403	3,569	3,629	3,287	3,110	2,991
4	22	2012	2,751	2,672	2,680	2,751	2,809	2,922	3,061	3,178	3,418	3,510	3,555	3,566
4	22	2012	3,490	3,426	3,420	3,452	3,374	3,400	3,543	3,681	3,689	3,353	3,267	3,133
4	23	2012	3,034	2,993	3,006	3,120	3,343	3,987	4,140	4,137	4,104	4,093	4,089	4,076
4	23	2012	4,090	4,067	3,941	3,912	3,849	3,896	3,867	4,004	3,995	3,804	3,386	3,300
4	24	2012	3,212	3,180	3,153	3,180	3,475	4,013	4,182	4,158	4,137	4,056	4,019	3,991
4	24	2012	3,978	3,936	3,879	3,744	3,757	3,819	3,814	3,925	3,950	3,738	3,318	3,195
4	25	2012	2,960	2,818	2,795	2,939	3,242	3,712	3,853	3,882	3,887	3,862	3,902	3,920
4	25	2012	3,934	3,918	3,881	3,835	3,852	3,848	3,868	3,936	3,885	3,689	3,221	3,160
4	26	2012	3,034	2,893	2,804	2,823	2,994	3,585	3,733	3,837	3,906	3,967	3,975	4,021
4	26	2012	4,034	4,008	3,968	3,905	3,833	3,789	3,737	3,783	3,807	3,610	3,190	3,060
4	27	2012	2,979	2,812	2,802	2,859	3,214	3,728	3,880	3,977	4,000	3,987	3,940	3,918
4	27	2012	3,871	3,841	3,786	3,707	3,642	3,609	3,601	3,670	3,706	3,587	3,190	3,066
4	28	2012	2,925	2,868	2,794	2,813	2,861	3,038	3,386	3,549	3,660	3,744	3,725	3,725
4	28	2012	3,665	3,582	3,566	3,591	3,595	3,581	3,563	3,621	3,620	3,467	3,078	2,953
4	29	2012	2,867	2,792	2,766	2,779	2,804	2,979	3,070	3,186	3,449	3,521	3,532	3,494
4	29	2012	3,497	3,462	3,422	3,453	3,514	3,527	3,547	3,632	3,678	3,373	3,025	2,901
4	30	2012	2,833	2,740	2,703	2,764	2,958	3,634	3,878	3,900	4,005	4,081	4,119	4,260
4	30	2012	4,263	4,235	4,248	4,157	4,181	4,152	4,064	3,992	3,997	3,835	3,380	3,192

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5	1	2012	2,986	2,881	2,859	2,904	3,090	3,624	3,831	3,932	3,977	4,042	4,111	4,092
5	1	2012	4,180	4,181	4,181	4,177	4,158	4,165	4,122	4,143	4,127	3,908	3,681	3,498
5	2	2012	3,203	3,132	3,070	3,145	3,271	3,786	3,945	4,024	4,154	4,296	4,460	4,528
5	2	2012	4,618	4,640	4,694	4,654	4,654	4,769	4,692	4,693	4,666	4,382	4,020	3,785
5	3	2012	3,628	3,448	3,325	3,343	3,518	3,842	4,062	4,175	4,374	4,508	4,682	4,763
5	3	2012	4,885	4,930	4,918	4,973	4,928	4,934	4,750	4,696	4,642	4,321	3,951	3,733
5	4	2012	3,532	3,240	3,204	3,150	3,550	3,837	4,026	4,185	4,254	4,423	4,498	4,508
5	4	2012	4,615	4,690	4,730	4,726	4,644	4,533	4,370	4,357	4,336	4,110	3,821	3,608
5	5	2012	3,166	3,068	3,005	2,903	2,982	3,064	3,173	3,594	3,737	3,899	3,972	4,082
5	5	2012	4,140	4,258	4,287	4,350	4,389	4,346	4,239	4,131	4,150	3,883	3,389	3,194
5	6	2012	3,048	2,965	2,777	2,751	2,739	2,779	2,932	3,122	3,603	3,726	3,912	4,084
5	6	2012	4,246	4,356	4,446	4,588	4,628	4,549	4,495	4,445	4,388	4,106	3,648	3,390
5	7	2012	3,221	3,159	3,111	3,134	3,252	3,858	4,016	4,152	4,294	4,368	4,461	4,581
5	7	2012	4,763	4,865	4,928	4,849	4,777	4,622	4,515	4,488	4,387	4,098	3,559	3,404
5	8	2012	3,264	3,163	3,087	3,073	3,297	3,711	3,961	3,997	4,065	4,186	4,273	4,391
5	8	2012	4,401	4,477	4,386	4,343	4,287	4,199	4,131	4,103	4,095	3,903	3,403	3,272
5	9	2012	3,124	2,933	2,851	2,970	3,174	3,689	3,897	3,932	4,000	4,087	4,158	4,166
5	9	2012	4,149	4,175	4,108	4,124	4,045	3,993	3,981	3,950	3,969	3,744	3,545	3,378
5	10	2012	3,055	2,930	2,896	2,940	3,089	3,568	3,699	3,781	3,832	3,865	3,890	3,911
5	10	2012	3,935	3,948	3,986	3,985	3,944	3,903	3,924	3,968	4,038	3,808	3,527	3,176
5	11	2012	3,032	2,837	2,837	2,894	3,087	3,547	3,702	3,853	3,932	3,944	3,979	4,031
5	11	2012	4,077	4,070	4,077	4,081	4,053	4,016	3,879	3,880	3,947	3,751	3,537	3,137
5	12	2012	2,865	2,747	2,715	2,683	2,748	2,931	3,040	3,404	3,574	3,672	3,685	3,725
5	12	2012	3,738	3,744	3,786	3,766	3,717	3,710	3,596	3,728	3,730	3,562	3,171	2,995
5	13	2012	2,816	2,680	2,636	2,639	2,617	2,678	2,732	3,188	3,361	3,474	3,490	3,577
5	13	2012	3,600	3,618	3,674	3,731	3,763	3,673	3,759	3,780	3,791	3,619	3,226	3,050
5	14	2012	2,848	2,760	2,756	2,782	2,930	3,565	3,808	3,913	4,104	4,196	4,291	4,337
5	14	2012	4,409	4,386	4,441	4,443	4,466	4,453	4,353	4,366	4,347	4,055	3,662	3,481
5	15	2012	3,060	2,919	2,857	2,878	3,071	3,625	3,752	3,906	4,037	4,241	4,268	4,349
5	15	2012	4,468	4,519	4,475	4,612	4,631	4,537	4,526	4,399	4,391	4,107	3,736	3,290
5	16	2012	3,143	2,958	2,896	2,933	3,133	3,628	3,778	3,926	4,039	4,145	4,245	4,321
5	16	2012	4,397	4,441	4,481	4,460	4,519	4,521	4,409	4,323	4,284	4,009	3,691	3,205
5	17	2012	3,084	2,886	2,842	2,904	3,086	3,566	3,766	3,894	4,006	4,084	4,125	4,145
5	17	2012	4,191	4,232	4,283	4,246	4,284	4,281	4,225	4,177	4,166	3,914	3,570	3,098
5	18	2012	2,892	2,851	2,822	2,877	3,008	3,517	3,720	3,750	3,841	3,943	4,103	4,199
5	18	2012	4,307	4,386	4,437	4,454	4,563	4,511	4,390	4,301	4,258	4,022	3,751	3,254
5	19	2012	3,072	2,923	2,857	2,804	2,872	2,907	3,268	3,471	3,749	3,945	4,060	4,223
5	19	2012	4,424	4,495	4,595	4,647	4,723	4,697	4,576	4,495	4,453	4,220	3,923	3,461
5	20	2012	3,129	2,933	2,866	2,839	2,798	2,796	3,199	3,377	3,731	4,026	4,163	4,354
5	20	2012	4,595	4,628	4,697	4,813	4,771	4,783	4,739	4,690	4,635	4,367	4,060	3,504
5	21	2012	3,276	3,042	2,952	3,083	3,234	3,795	4,035	4,258	4,336	4,514	4,506	4,437
5	21	2012	4,479	4,575	4,604	4,567	4,490	4,426	4,308	4,144	4,174	3,946	3,621	3,376
5	22	2012	3,054	2,837	2,861	2,884	3,014	3,379	3,751	3,818	3,946	4,109	4,178	4,235
5	22	2012	4,296	4,354	4,398	4,406	4,395	4,341	4,325	4,272	4,190	3,945	3,650	3,162
5	23	2012	3,068	2,867	2,791	2,889	3,021	3,509	3,752	3,931	4,059	4,219	4,331	4,434
5	23	2012	4,522	4,625	4,647	4,685	4,728	4,727	4,661	4,528	4,512	4,282	3,888	3,629
5	24	2012	3,194	3,044	2,966	2,958	3,129	3,670	3,853	3,993	4,160	4,341	4,456	4,581
5	24	2012	4,685	4,778	4,860	4,937	4,948	4,961	4,915	4,729	4,617	4,369	4,051	3,813
5	25	2012	3,713	3,617	3,578	3,558	3,673	4,020	4,258	4,469	4,638	4,839	5,023	5,227
5	25	2012	5,367	5,492	5,543	5,558	5,498	5,432	5,276	5,137	5,051	4,749	4,409	4,121
5	26	2012	3,688	3,530	3,395	3,309	3,243	3,245	3,423	3,759	4,055	4,238	4,612	4,829
5	26	2012	4,940	5,015	5,072	5,109	5,117	5,146	5,035	4,872	4,824	4,501	4,221	3,921
5	27	2012	3,679	3,503	3,375	3,246	3,235	3,209	3,382	3,618	3,950	4,212	4,496	4,745
5	27	2012	4,795	4,911	4,974	5,023	5,040	5,049	4,898	4,826	4,690	4,490	4,181	3,899
5	28	2012	3,610	3,473	3,349	3,312	3,276	3,282	3,377	3,681	3,995	4,435	4,675	4,805
5	28	2012	4,966	5,001	5,076	5,079	5,069	5,022	5,054	4,940	4,895	4,656	4,353	4,120
5	29	2012	3,842	3,704	3,582	3,584	3,672	4,015	4,206	4,293	4,348	4,455	4,535	4,612
5	29	2012	4,718	4,751	4,729	4,798	4,905	4,892	4,809	4,662	4,512	4,236	3,921	3,613
5	30	2012	3,223	3,101	3,007	2,994	3,017	3,496	3,755	4,011	4,199	4,370	4,462	4,527
5	30	2012	4,561	4,548	4,565	4,587	4,514	4,523	4,467	4,406	4,311	4,111	3,723	3,387
5	31	2012	3,024	2,868	2,833	2,870	2,957	3,426	3,693	3,907	4,004	4,118	4,239	4,338
5	31	2012	4,407	4,350	4,381	4,421	4,336	4,229	4,166	4,077	4,083	3,903	3,593	3,332

Month	Day	Year	Hr 1&13	Hr 2&14	Hr 3&15	Hr 4&16	Hr 5&17	Hr 6&18	Hr 7&19	Hr 8&20	Hr 9&21	Hr 10&22	Hr 11&23	Hr 12&24
6	1	2012	2,947	2,798	2,729	2,786	2,861	3,365	3,475	3,596	3,674	3,762	3,728	3,738
6	1	2012	3,720	3,719	3,626	3,595	3,544	3,454	3,410	3,413	3,464	3,360	3,214	3,017
6	2	2012	2,733	2,523	2,540	2,574	2,599	2,606	2,997	3,098	3,267	3,266	3,359	3,395
6	2	2012	3,374	3,360	3,339	3,332	3,321	3,337	3,300	3,321	3,309	3,180	3,086	2,718
6	3	2012	2,620	2,520	2,474	2,461	2,485	2,488	2,817	2,989	3,109	3,217	3,339	3,439
6	3	2012	3,447	3,605	3,667	3,710	3,762	3,792	3,791	3,717	3,772	3,685	3,386	3,261
6	4	2012	2,930	2,807	2,691	2,744	2,863	3,308	3,532	3,847	4,063	4,225	4,261	4,340
6	4	2012	4,354	4,406	4,398	4,409	4,419	4,384	4,294	4,247	4,203	4,089	3,764	3,416
6	5	2012	3,069	2,883	2,872	2,906	3,038	3,192	3,683	3,912	4,052	4,153	4,255	4,278
6	5	2012	4,361	4,398	4,343	4,325	4,309	4,256	4,174	4,134	4,165	3,982	3,654	3,197
6	6	2012	2,994	2,891	2,804	2,840	2,965	3,386	3,606	3,791	3,926	4,023	4,094	4,159
6	6	2012	4,217	4,247	4,284	4,313	4,396	4,333	4,338	4,270	4,244	4,055	3,712	3,396
6	7	2012	2,997	2,856	2,819	2,867	3,003	3,434	3,700	3,883	4,067	4,197	4,314	4,379
6	7	2012	4,577	4,663	4,678	4,725	4,700	4,725	4,641	4,443	4,385	4,217	3,896	3,554
6	8	2012	3,134	2,951	2,899	2,895	3,036	3,441	3,622	3,851	4,119	4,314	4,448	4,581
6	8	2012	4,739	4,850	4,917	4,946	4,922	4,907	4,782	4,640	4,489	4,286	3,969	3,584
6	9	2012	3,367	3,232	3,068	3,052	3,072	3,077	3,277	3,449	3,745	4,004	4,209	4,421
6	9	2012	4,514	4,585	4,668	4,790	4,891	4,878	4,808	4,645	4,447	4,253	3,886	3,575
6	10	2012	3,362	3,246	3,076	3,011	2,968	3,006	3,059	3,414	3,683	3,956	4,233	4,507
6	10	2012	4,693	4,796	4,891	4,968	4,975	4,966	4,862	4,745	4,654	4,503	4,139	3,871
6	11	2012	3,701	3,478	3,396	3,372	3,501	3,822	4,020	4,309	4,548	4,727	4,854	4,937
6	11	2012	5,134	5,216	5,244	5,255	5,240	5,234	5,130	4,998	4,967	4,728	4,312	3,955
6	12	2012	3,448	3,241	3,161	3,162	3,312	3,806	4,054	4,278	4,534	4,684	4,776	4,862
6	12	2012	5,003	5,062	5,066	5,101	5,092	5,012	4,875	4,693	4,564	4,328	3,822	3,540
6	13	2012	3,094	2,987	2,921	2,895	3,016	3,236	3,570	3,734	3,893	4,042	4,188	4,309
6	13	2012	4,473	4,555	4,685	4,822	4,875	4,871	4,768	4,538	4,481	4,249	3,827	3,592
6	14	2012	3,156	3,041	2,981	2,936	3,085	3,205	3,688	3,862	4,039	4,177	4,388	4,574
6	14	2012	4,733	4,825	4,902	4,966	5,031	5,069	4,974	4,816	4,668	4,492	4,048	3,531
6	15	2012	3,208	3,041	3,015	3,003	3,027	3,494	3,717	4,044	4,308	4,473	4,720	4,942
6	15	2012	5,092	5,266	5,355	5,399	5,454	5,379	5,266	5,110	4,973	4,732	4,370	4,105
6	16	2012	3,433	3,241	3,121	3,063	3,104	3,117	3,546	3,836	4,288	4,602	4,914	5,102
6	16	2012	5,198	5,313	5,366	5,375	5,368	5,286	5,176	5,026	4,916	4,750	4,409	4,061
6	17	2012	3,504	3,321	3,310	3,225	3,201	3,130	3,410	3,723	4,026	4,271	4,440	4,578
6	17	2012	4,632	4,741	4,881	4,975	5,039	5,021	4,940	4,792	4,761	4,700	4,266	3,997
6	18	2012	3,611	3,353	3,311	3,327	3,461	3,962	4,313	4,656	4,957	5,120	5,343	5,518
6	18	2012	5,663	5,772	5,821	5,851	5,837	5,772	5,640	5,528	5,428	5,190	4,747	4,433
6	19	2012	4,205	3,971	3,872	3,868	3,908	4,089	4,349	4,657	4,928	5,229	5,466	5,629
6	19	2012	5,790	5,900	5,937	5,968	5,991	5,880	5,767	5,637	5,573	5,284	4,900	4,584
6	20	2012	4,330	4,039	3,845	3,798	3,753	3,915	4,236	4,555	4,881	5,186	5,340	5,533
6	20	2012	5,683	5,777	5,849	5,883	5,938	5,880	5,718	5,580	5,516	5,260	4,865	4,551
6	21	2012	4,327	4,143	4,032	3,965	4,055	4,211	4,419	4,613	4,965	5,265	5,457	5,626
6	21	2012	5,765	5,864	5,910	5,880	5,731	5,544	5,372	5,265	5,141	4,984	4,652	4,348
6	22	2012	4,015	3,808	3,695	3,650	3,688	3,839	4,113	4,482	4,725	4,972	5,110	5,229
6	22	2012	5,379	5,410	5,484	5,466	5,458	5,371	5,218	5,035	4,809	4,606	4,257	3,872
6	23	2012	3,341	3,139	3,016	2,978	2,916	2,958	3,403	3,645	3,981	4,281	4,461	4,674
6	23	2012	4,842	4,929	4,917	5,104	5,145	5,019	4,910	4,758	4,661	4,437	4,084	3,782
6	24	2012	3,559	3,207	3,108	3,020	3,003	2,971	3,127	3,598	4,003	4,393	4,679	4,892
6	24	2012	5,034	5,092	5,230	5,329	5,445	5,406	5,368	5,219	5,134	4,857	4,620	4,252
6	25	2012	3,942	3,795	3,638	3,645	3,802	3,910	4,285	4,602	4,816	5,107	5,258	5,397
6	25	2012	5,445	5,468	5,518	5,460	5,485	5,333	5,241	5,083	4,863	4,629	4,266	3,940
6	26	2012	3,592	3,381	3,281	3,289	3,346	3,538	3,830	4,062	4,281	4,442	4,470	4,619
6	26	2012	4,723	4,890	4,911	4,998	5,063	5,045	4,954	4,783	4,732	4,510	4,112	3,712
6	27	2012	3,447	3,285	3,200	3,191	3,314	3,549	3,767	4,060	4,280	4,493	4,726	4,819
6	27	2012	4,973	5,206	5,308	5,457	5,468	5,451	5,432	5,284	5,140	4,912	4,565	4,171
6	28	2012	3,947	3,703	3,528	3,529	3,630	3,872	4,105	4,435	4,809	5,054	5,344	5,681
6	28	2012	5,986	6,225	6,335	6,403	6,424	6,382	6,262	6,076	5,842	5,626	5,243	4,901
6	29	2012	4,659	4,456	4,324	4,251	4,333	4,406	4,598	4,822	5,113	5,447	5,769	6,082
6	29	2012	6,246	6,293	6,005	5,643	5,453	5,387	5,302	5,119	5,022	4,866	4,539	4,271
6	30	2012	4,025	3,868	3,702	3,603	3,529	3,498	3,628	3,943	4,254	4,547	4,814	5,075
6	30	2012	5,288	5,434	5,540	5,550	5,480	5,417	5,278	5,127	5,016	4,840	4,617	4,344

Month	Day	Year	Hr 1&13	Hr 2&14	Hr 3&15	Hr 4&16	Hr 5&17	Hr 6&18	Hr 7&19	Hr 8&20	Hr 9&21	Hr 10&22	Hr 11&23	Hr 12&24
7	1	2012	4,067	3,857	3,642	3,504	3,546	3,497	3,606	3,892	4,277	4,576	4,893	5,082
7	1	2012	5,349	5,406	5,445	5,399	5,317	5,210	5,040	4,920	4,831	4,654	4,395	4,119
7	2	2012	3,774	3,634	3,538	3,532	3,637	3,786	4,054	4,423	4,741	4,958	5,268	5,554
7	2	2012	5,739	5,844	6,014	6,068	6,050	5,976	5,849	5,690	5,619	5,376	4,973	4,690
7	3	2012	4,311	4,054	3,878	3,835	3,900	3,961	4,203	4,531	4,731	5,089	5,322	5,499
7	3	2012	5,726	5,825	5,915	5,997	5,965	5,939	5,798	5,631	5,530	5,325	4,958	4,625
7	4	2012	4,360	4,070	3,882	3,743	3,717	3,565	3,615	3,958	4,377	4,777	5,081	5,329
7	4	2012	5,505	5,587	5,659	5,723	5,719	5,654	5,511	5,382	5,260	5,054	4,846	4,566
7	5	2012	4,285	4,050	3,863	3,803	3,863	3,991	4,227	4,595	5,027	5,456	5,701	6,006
7	5	2012	6,155	6,242	6,295	6,302	6,277	6,216	6,087	5,922	5,867	5,582	5,204	4,874
7	6	2012	4,643	4,397	4,184	4,080	4,137	4,254	4,500	4,809	5,096	5,500	5,824	6,061
7	6	2012	6,218	6,312	6,358	6,352	6,335	6,254	6,143	6,068	5,928	5,687	5,293	5,034
7	7	2012	4,773	4,510	4,363	4,207	4,064	4,062	4,206	4,553	4,969	5,346	5,611	5,867
7	7	2012	5,953	5,988	6,055	6,086	6,061	5,965	5,847	5,679	5,547	5,448	5,129	4,861
7	8	2012	4,604	4,443	4,170	4,031	3,943	3,897	3,924	4,334	4,558	4,831	5,061	5,306
7	8	2012	5,371	5,304	5,199	5,036	4,906	4,806	4,768	4,588	4,538	4,383	4,182	3,990
7	9	2012	3,891	3,682	3,470	3,511	3,606	3,878	4,135	4,416	4,558	4,841	4,948	5,178
7	9	2012	5,280	5,410	5,477	5,534	5,590	5,530	5,397	5,319	5,129	4,883	4,516	4,257
7	10	2012	4,015	3,784	3,597	3,584	3,653	3,904	4,122	4,388	4,562	4,888	5,098	5,264
7	10	2012	5,495	5,635	5,694	5,745	5,740	5,638	5,519	5,383	5,182	4,949	4,601	4,330
7	11	2012	4,066	3,930	3,700	3,553	3,756	3,983	4,138	4,383	4,598	4,852	5,124	5,392
7	11	2012	5,589	5,696	5,805	5,817	5,839	5,762	5,687	5,506	5,349	5,124	4,710	4,370
7	12	2012	4,092	3,845	3,695	3,682	3,702	3,859	4,140	4,427	4,697	5,035	5,257	5,501
7	12	2012	5,710	5,800	5,832	5,851	5,792	5,702	5,555	5,479	5,376	5,137	4,760	4,450
7	13	2012	4,165	3,961	3,839	3,789	3,821	3,975	4,250	4,552	4,835	5,073	5,282	5,470
7	13	2012	5,564	5,669	5,720	5,739	5,621	5,594	5,455	5,318	5,252	4,957	4,628	4,356
7	14	2012	4,227	4,071	3,871	3,771	3,679	3,743	3,873	4,111	4,407	4,631	4,786	4,873
7	14	2012	4,993	5,049	5,092	5,115	5,078	5,028	4,946	4,794	4,690	4,513	4,304	4,074
7	15	2012	3,851	3,666	3,611	3,495	3,415	3,370	3,445	3,898	4,219	4,482	4,755	5,014
7	15	2012	5,154	5,289	5,430	5,483	5,582	5,546	5,470	5,283	5,215	5,025	4,750	4,476
7	16	2012	4,185	3,896	3,768	3,824	3,924	4,098	4,404	4,760	5,049	5,328	5,603	5,790
7	16	2012	5,987	6,102	6,188	6,174	6,168	6,095	5,988	5,829	5,686	5,476	5,110	4,791
7	17	2012	4,546	4,292	4,183	4,130	4,174	4,400	4,685	4,918	5,242	5,532	5,806	6,049
7	17	2012	6,226	6,299	6,329	6,287	6,157	5,967	5,776	5,694	5,574	5,365	4,934	4,699
7	18	2012	4,521	4,224	3,991	3,960	4,154	4,366	4,661	4,963	5,210	5,517	5,851	6,080
7	18	2012	6,145	6,113	6,062	5,948	5,804	5,671	5,515	5,431	5,357	5,117	4,820	4,532
7	19	2012	4,366	4,205	4,152	4,064	4,193	4,436	4,558	4,768	4,945	5,101	5,239	5,292
7	19	2012	5,489	5,665	5,827	5,851	5,849	5,626	5,428	5,232	5,141	4,949	4,632	4,300
7	20	2012	4,076	3,868	3,828	3,812	3,898	4,095	4,328	4,474	4,581	4,733	4,820	4,871
7	20	2012	4,890	4,907	4,917	4,929	4,948	4,872	4,780	4,682	4,569	4,394	4,095	3,853
7	21	2012	3,493	3,378	3,199	3,172	3,185	3,311	3,375	3,535	3,877	4,190	4,405	4,484
7	21	2012	4,658	4,824	4,946	5,040	5,116	5,073	4,939	4,814	4,704	4,504	4,205	3,848
7	22	2012	3,512	3,484	3,348	3,237	3,216	3,234	3,255	3,577	3,964	4,332	4,602	4,866
7	22	2012	5,014	5,210	5,414	5,472	5,561	5,541	5,429	5,327	5,237	4,879	4,623	4,441
7	23	2012	4,042	3,895	3,812	3,756	3,883	4,116	4,393	4,650	4,983	5,295	5,551	5,743
7	23	2012	5,984	6,134	6,208	6,240	6,215	6,227	6,094	5,991	5,910	5,658	5,326	5,090
7	24	2012	4,851	4,720	4,537	4,488	4,540	4,812	5,002	5,093	5,227	5,316	5,425	5,591
7	24	2012	5,788	5,913	6,069	6,091	6,104	5,960	5,886	5,792	5,615	5,276	4,879	4,576
7	25	2012	4,315	4,080	3,974	3,969	4,054	4,285	4,507	4,811	5,080	5,365	5,587	5,856
7	25	2012	6,096	6,292	6,402	6,492	6,494	6,422	6,384	6,257	6,144	5,914	5,563	5,268
7	26	2012	5,060	4,772	4,540	4,465	4,491	4,819	4,963	5,116	5,310	5,555	5,730	5,909
7	26	2012	6,001	6,059	6,126	6,002	6,019	5,925	5,771	5,590	5,500	5,251	4,878	4,613
7	27	2012	4,333	4,059	3,896	3,886	3,968	4,238	4,449	4,654	4,955	5,228	5,463	5,624
7	27	2012	5,770	5,787	5,696	5,565	5,504	5,393	5,256	5,022	4,957	4,596	4,125	3,795
7	28	2012	3,623	3,499	3,270	3,172	3,222	3,293	3,397	3,603	3,839	4,110	4,425	4,735
7	28	2012	4,831	4,911	5,043	5,064	5,089	4,983	4,872	4,553	4,484	4,098	3,852	3,582
7	29	2012	3,384	3,282	3,179	3,058	3,017	2,999	3,045	3,316	3,574	3,884	4,096	4,318
7	29	2012	4,793	4,897	5,006	5,088	5,146	5,150	5,100	4,961	4,871	4,297	4,010	3,757
7	30	2012	3,519	3,454	3,266	3,329	3,471	3,713	4,008	4,360	4,675	4,961	5,246	5,474
7	30	2012	5,661	5,789	5,841	5,827	5,836	5,740	5,598	5,501	5,434	5,134	4,817	4,503
7	31	2012	4,162	3,947	3,824	3,783	3,855	4,096	4,329	4,526	4,747	4,956	5,156	5,351
7	31	2012	5,537	5,730	5,848	5,869	5,743	5,726	5,563	5,371	5,226	4,908	4,634	4,446

Month	Day	Year	Hr 1&13	Hr 2&14	Hr 3&15	Hr 4&16	Hr 5&17	Hr 6&18	Hr 7&19	Hr 8&20	Hr 9&21	Hr 10&22	Hr 11&23	Hr 12&24
8	1	2012	4,044	3,842	3,788	3,679	3,715	3,843	4,038	4,310	4,585	4,859	5,104	5,310
8	1	2012	5,512	5,618	5,651	5,733	5,754	5,781	5,630	5,442	5,272	4,898	4,538	4,223
8	2	2012	3,801	3,662	3,506	3,524	3,604	3,794	4,033	4,281	4,540	4,847	5,022	5,318
8	2	2012	5,509	5,710	5,811	5,910	5,928	5,892	5,685	5,613	5,525	5,200	4,820	4,584
8	3	2012	4,273	4,045	3,827	3,847	3,861	4,149	4,370	4,595	4,881	5,136	5,373	5,459
8	3	2012	5,605	5,681	5,709	5,719	5,671	5,599	5,545	5,415	5,348	5,022	4,778	4,469
8	4	2012	4,127	3,955	3,813	3,688	3,728	3,850	3,927	4,161	4,513	4,857	5,161	5,431
8	4	2012	5,560	5,639	5,557	5,661	5,672	5,602	5,468	5,224	5,174	4,902	4,681	4,215
8	5	2012	4,000	3,912	3,716	3,709	3,699	3,631	3,696	3,753	3,924	4,232	4,498	4,653
8	5	2012	4,827	4,993	5,125	5,254	5,277	5,263	5,149	4,992	4,923	4,611	4,204	3,917
8	6	2012	3,714	3,547	3,335	3,356	3,557	3,847	3,985	4,245	4,558	4,816	5,036	5,227
8	6	2012	5,425	5,515	5,617	5,628	5,668	5,668	5,524	5,363	5,241	4,828	4,446	4,044
8	7	2012	3,770	3,570	3,465	3,463	3,576	3,826	3,967	4,206	4,535	4,840	5,130	5,342
8	7	2012	5,544	5,688	5,794	5,897	5,928	5,878	5,787	5,583	5,495	5,113	4,745	4,394
8	8	2012	4,043	3,745	3,662	3,631	3,686	3,949	4,085	4,361	4,738	5,013	5,363	5,598
8	8	2012	5,694	5,969	6,046	6,038	6,054	5,961	5,790	5,642	5,506	5,185	4,818	4,422
8	9	2012	4,112	3,957	3,751	3,752	3,847	4,162	4,342	4,493	4,663	4,840	4,887	5,062
8	9	2012	5,213	5,388	5,484	5,518	5,503	5,421	5,236	5,136	5,124	4,746	4,216	3,887
8	10	2012	3,745	3,603	3,541	3,491	3,574	3,910	4,089	4,176	4,319	4,432	4,529	4,594
8	10	2012	4,640	4,703	4,649	4,624	4,580	4,500	4,283	4,219	4,208	4,029	3,584	3,344
8	11	2012	2,996	2,919	2,774	2,767	2,790	2,862	2,969	3,419	3,634	3,761	4,001	4,140
8	11	2012	4,203	4,222	4,264	4,406	4,378	4,398	4,301	4,212	4,158	3,890	3,573	3,323
8	12	2012	2,999	2,896	2,751	2,693	2,700	2,762	2,780	3,259	3,404	3,597	3,849	4,013
8	12	2012	4,154	4,289	4,399	4,469	4,509	4,440	4,391	4,301	4,303	4,152	3,811	3,569
8	13	2012	3,414	3,148	3,007	2,985	3,237	3,708	3,986	4,143	4,284	4,371	4,458	4,595
8	13	2012	4,700	4,786	4,794	4,800	4,790	4,722	4,652	4,684	4,603	4,304	3,988	3,730
8	14	2012	3,378	3,249	3,171	3,157	3,228	3,730	3,922	4,055	4,220	4,319	4,396	4,480
8	14	2012	4,555	4,635	4,696	4,750	4,806	4,787	4,712	4,670	4,643	4,397	3,988	3,677
8	15	2012	3,550	3,435	3,336	3,336	3,529	3,785	3,983	4,135	4,384	4,562	4,774	4,863
8	15	2012	5,140	5,205	5,241	5,306	5,402	5,349	5,294	5,126	5,056	4,706	4,239	3,896
8	16	2012	3,705	3,594	3,194	3,209	3,612	3,893	4,111	4,332	4,504	4,739	4,837	4,941
8	16	2012	4,982	4,959	4,899	4,943	4,933	4,832	4,705	4,578	4,493	4,263	3,981	3,731
8	17	2012	3,524	3,206	3,116	3,206	3,306	3,866	4,072	4,241	4,387	4,509	4,519	4,586
8	17	2012	4,733	4,807	4,758	4,794	4,803	4,698	4,558	4,404	4,358	4,059	3,741	3,434
8	18	2012	3,093	3,000	2,831	2,816	2,863	2,942	3,057	3,411	3,655	3,854	3,993	3,942
8	18	2012	4,067	4,142	4,241	4,354	4,313	4,265	4,185	4,019	4,105	3,788	3,495	3,296
8	19	2012	2,964	2,841	2,693	2,686	2,715	2,766	2,889	3,188	3,358	3,592	3,784	3,939
8	19	2012	4,018	4,134	4,184	4,241	4,273	4,284	4,217	4,171	4,149	3,940	3,516	3,352
8	20	2012	3,198	2,877	2,812	2,937	3,008	3,590	3,831	4,038	4,178	4,295	4,476	4,643
8	20	2012	4,702	4,830	4,820	4,841	4,796	4,727	4,607	4,622	4,527	4,163	3,774	3,493
8	21	2012	3,157	3,039	2,913	3,010	3,227	3,543	3,861	4,028	4,223	4,425	4,487	4,629
8	21	2012	4,739	4,811	4,771	4,800	4,821	4,724	4,728	4,646	4,604	4,241	3,845	3,495
8	22	2012	3,188	3,106	3,010	2,973	3,051	3,589	3,733	3,889	4,073	4,251	4,400	4,546
8	22	2012	4,685	4,788	4,900	4,996	5,030	5,002	4,881	4,792	4,762	4,350	4,024	3,638
8	23	2012	3,278	3,183	2,909	3,042	3,120	3,512	3,974	4,101	4,313	4,553	4,731	4,930
8	23	2012	5,136	5,232	5,334	5,414	5,469	5,429	5,277	5,191	5,048	4,660	4,279	3,885
8	24	2012	3,439	3,298	3,144	3,165	3,260	3,522	3,987	4,182	4,412	4,639	4,872	5,134
8	24	2012	5,347	5,457	5,550	5,570	5,645	5,504	5,329	5,140	5,013	4,715	4,329	3,976
8	25	2012	3,502	3,358	3,223	3,177	3,150	3,206	3,480	3,696	4,050	4,379	4,709	4,931
8	25	2012	5,163	5,207	5,299	5,396	5,381	5,312	5,096	4,995	4,846	4,559	4,170	3,810
8	26	2012	3,419	3,262	3,156	3,087	3,060	3,069	3,329	3,505	3,847	4,204	4,531	4,747
8	26	2012	4,913	4,962	5,054	5,133	5,171	5,112	5,079	5,071	4,944	4,624	4,291	4,009
8	27	2012	3,644	3,542	3,437	3,483	3,622	4,043	4,551	4,726	4,804	4,866	4,962	5,099
8	27	2012	5,228	5,347	5,424	5,488	5,495	5,461	5,323	5,162	5,020	4,665	4,310	3,937
8	28	2012	3,449	3,287	3,170	3,163	3,324	3,820	3,991	4,269	4,451	4,685	4,817	5,060
8	28	2012	5,167	5,295	5,363	5,404	5,437	5,343	5,213	5,117	4,907	4,580	4,158	3,787
8	29	2012	3,621	3,279	3,197	3,146	3,261	3,772	4,028	4,184	4,366	4,533	4,675	4,867
8	29	2012	5,068	5,226	5,300	5,399	5,445	5,378	5,207	5,180	5,022	4,609	4,116	3,752
8	30	2012	3,600	3,237	3,148	3,172	3,245	3,802	4,024	4,241	4,343	4,604	4,754	4,942
8	30	2012	5,175	5,342	5,476	5,521	5,583	5,544	5,353	5,244	5,060	4,696	4,297	3,930
8	31	2012	3,739	3,415	3,321	3,362	3,459	3,989	4,261	4,420	4,669	4,930	5,111	5,225
8	31	2012	5,283	5,357	5,396	5,448	5,427	5,320	5,184	5,125	5,027	4,394	4,121	3,856

Month	Day	Year	Hr 1&13	Hr 2&14	Hr 3&15	Hr 4&16	Hr 5&17	Hr 6&18	Hr 7&19	Hr 8&20	Hr 9&21	Hr 10&22	Hr 11&23	Hr 12&24
9	1	2012	3,684	3,345	3,260	3,124	3,131	3,293	3,543	3,663	3,908	4,059	4,249	4,429
9	1	2012	4,488	4,546	4,661	4,708	4,755	4,556	4,510	4,494	4,280	4,064	3,854	3,631
9	2	2012	3,424	3,287	3,059	2,924	2,913	2,975	3,122	3,446	3,560	3,699	3,831	3,899
9	2	2012	4,087	4,231	4,208	4,219	4,214	4,197	4,151	4,169	3,965	3,631	3,490	3,305
9	3	2012	3,159	2,852	2,724	2,744	2,760	2,912	2,948	3,062	3,483	3,677	3,883	4,169
9	3	2012	4,406	4,485	4,532	4,602	4,663	4,684	4,642	4,639	4,573	3,960	3,715	3,515
9	4	2012	3,172	3,074	2,964	3,007	3,250	3,706	3,969	4,353	4,542	4,772	5,030	5,311
9	4	2012	5,472	5,590	5,629	5,701	5,703	5,643	5,532	5,514	5,323	4,926	4,593	4,243
9	5	2012	3,940	3,608	3,505	3,470	3,623	4,194	4,396	4,493	4,750	5,037	5,186	5,267
9	5	2012	5,157	5,056	4,922	4,836	4,837	4,861	4,763	4,854	4,726	4,410	4,006	3,739
9	6	2012	3,672	3,467	3,404	3,416	3,572	4,001	4,211	4,308	4,473	4,671	4,895	5,141
9	6	2012	5,315	5,529	5,642	5,628	5,736	5,597	5,473	5,493	5,172	4,696	4,399	4,025
9	7	2012	3,885	3,514	3,426	3,396	3,532	4,030	4,265	4,331	4,576	4,908	5,043	5,239
9	7	2012	5,272	5,227	5,211	5,193	5,114	5,010	4,951	4,836	4,682	4,448	4,079	3,723
9	8	2012	3,382	3,116	3,065	3,045	2,996	3,138	3,470	3,630	3,801	3,945	4,022	4,004
9	8	2012	3,954	3,969	4,023	4,040	4,015	3,952	3,848	3,950	3,886	3,742	3,258	3,012
9	9	2012	2,797	2,718	2,675	2,629	2,670	2,680	2,747	3,094	3,316	3,415	3,611	3,679
9	9	2012	3,762	3,782	3,838	3,934	3,984	3,928	3,900	3,975	3,879	3,756	3,450	3,091
9	10	2012	2,875	2,791	2,749	2,805	2,978	3,700	3,884	3,928	4,049	4,251	4,302	4,378
9	10	2012	4,452	4,506	4,562	4,550	4,582	4,592	4,496	4,540	4,376	4,053	3,729	3,426
9	11	2012	3,019	2,936	2,903	2,914	3,127	3,632	3,932	4,077	4,167	4,324	4,354	4,434
9	11	2012	4,592	4,640	4,686	4,746	4,738	4,690	4,609	4,598	4,438	4,149	3,750	3,262
9	12	2012	3,047	2,884	2,927	2,911	3,041	3,694	3,906	3,994	4,114	4,272	4,395	4,571
9	12	2012	4,684	4,767	4,825	4,858	4,858	4,800	4,692	4,740	4,556	4,289	3,899	3,414
9	13	2012	3,170	3,090	3,019	3,006	3,203	3,907	4,197	4,297	4,386	4,584	4,676	4,831
9	13	2012	4,943	4,999	4,998	5,014	4,994	4,919	4,830	4,861	4,726	4,388	4,043	3,485
9	14	2012	3,218	3,113	2,985	3,065	3,243	3,807	4,087	4,146	4,251	4,348	4,336	4,339
9	14	2012	4,359	4,354	4,311	4,275	4,179	4,129	4,059	4,216	4,045	3,832	3,513	3,218
9	15	2012	2,837	2,792	2,701	2,701	2,792	2,855	3,196	3,424	3,675	3,778	3,847	3,853
9	15	2012	3,881	3,873	3,900	3,939	3,943	3,868	3,856	3,904	3,635	3,492	3,116	2,899
9	16	2012	2,794	2,757	2,650	2,649	2,641	2,675	2,828	3,114	3,358	3,548	3,624	3,750
9	16	2012	3,862	3,881	3,972	4,068	4,047	4,110	4,086	4,161	4,051	3,798	3,548	3,129
9	17	2012	3,007	2,813	2,803	2,805	2,963	3,627	3,957	4,090	4,172	4,301	4,370	4,377
9	17	2012	4,456	4,419	4,391	4,323	4,314	4,318	4,353	4,464	4,365	4,051	3,818	3,362
9	18	2012	3,192	3,172	3,057	3,140	3,293	3,858	4,195	4,137	4,190	4,201	4,199	4,243
9	18	2012	4,183	4,251	4,206	4,136	4,086	3,971	4,015	4,107	3,967	3,682	3,386	3,017
9	19	2012	2,875	2,787	2,775	2,860	3,055	3,623	3,837	3,872	3,879	3,912	3,907	3,943
9	19	2012	3,969	3,943	4,036	4,047	4,011	4,018	4,046	4,194	4,034	3,782	3,481	3,257
9	20	2012	2,943	2,818	2,865	2,863	3,130	3,732	4,000	4,008	4,033	4,160	4,119	4,139
9	20	2012	4,198	4,184	4,162	4,102	4,123	3,982	4,089	4,214	4,177	3,809	3,546	3,148
9	21	2012	3,008	2,902	2,802	2,843	3,092	3,722	3,961	3,948	3,952	4,119	4,127	4,092
9	21	2012	4,152	4,115	4,101	4,053	3,954	3,866	3,930	3,915	3,887	3,678	3,413	3,022
9	22	2012	2,886	2,767	2,705	2,733	2,708	2,932	3,099	3,453	3,630	3,719	3,817	3,792
9	22	2012	3,737	3,745	3,678	3,651	3,641	3,647	3,648	3,702	3,605	3,409	3,210	2,780
9	23	2012	2,717	2,676	2,633	2,642	2,707	2,847	2,877	3,322	3,433	3,435	3,510	3,569
9	23	2012	3,546	3,520	3,524	3,544	3,561	3,614	3,724	3,862	3,716	3,558	3,351	3,036
9	24	2012	2,971	2,858	2,861	2,932	3,119	3,756	4,059	4,096	4,102	4,141	4,021	4,076
9	24	2012	4,152	4,155	4,109	4,101	4,056	4,075	4,100	4,251	4,096	3,840	3,520	3,150
9	25	2012	3,037	2,968	2,892	2,979	3,130	3,779	3,962	4,004	4,126	4,173	4,184	4,215
9	25	2012	4,199	4,149	4,149	4,134	4,148	4,136	4,169	4,250	4,138	3,867	3,535	3,211
9	26	2012	3,093	2,963	2,935	2,902	3,098	3,701	4,003	3,998	4,038	4,106	4,135	4,176
9	26	2012	4,204	4,157	4,115	4,057	4,104	4,079	4,134	4,223	4,053	3,828	3,291	3,135
9	27	2012	2,885	2,824	2,779	2,797	2,991	3,555	3,957	3,999	4,073	4,203	4,236	4,282
9	27	2012	4,288	4,319	4,325	4,316	4,309	4,259	4,253	4,386	4,250	3,662	3,380	3,049
9	28	2012	2,947	2,823	2,768	2,779	2,932	3,495	3,736	3,758	3,799	3,881	3,883	3,934
9	28	2012	3,895	3,909	3,903	3,903	3,826	3,720	3,709	3,763	3,583	3,402	3,180	2,817
9	29	2012	2,651	2,574	2,542	2,585	2,622	2,739	2,870	2,927	2,981	3,307	3,384	3,386
9	29	2012	3,400	3,411	3,450	3,441	3,467	3,412	3,393	3,420	3,351	3,159	2,800	2,641
9	30	2012	2,557	2,509	2,474	2,460	2,519	2,517	2,659	2,747	2,847	3,136	3,208	3,280
9	30	2012	3,305	3,302	3,339	3,374	3,387	3,388	3,470	3,493	3,371	3,217	2,860	2,730

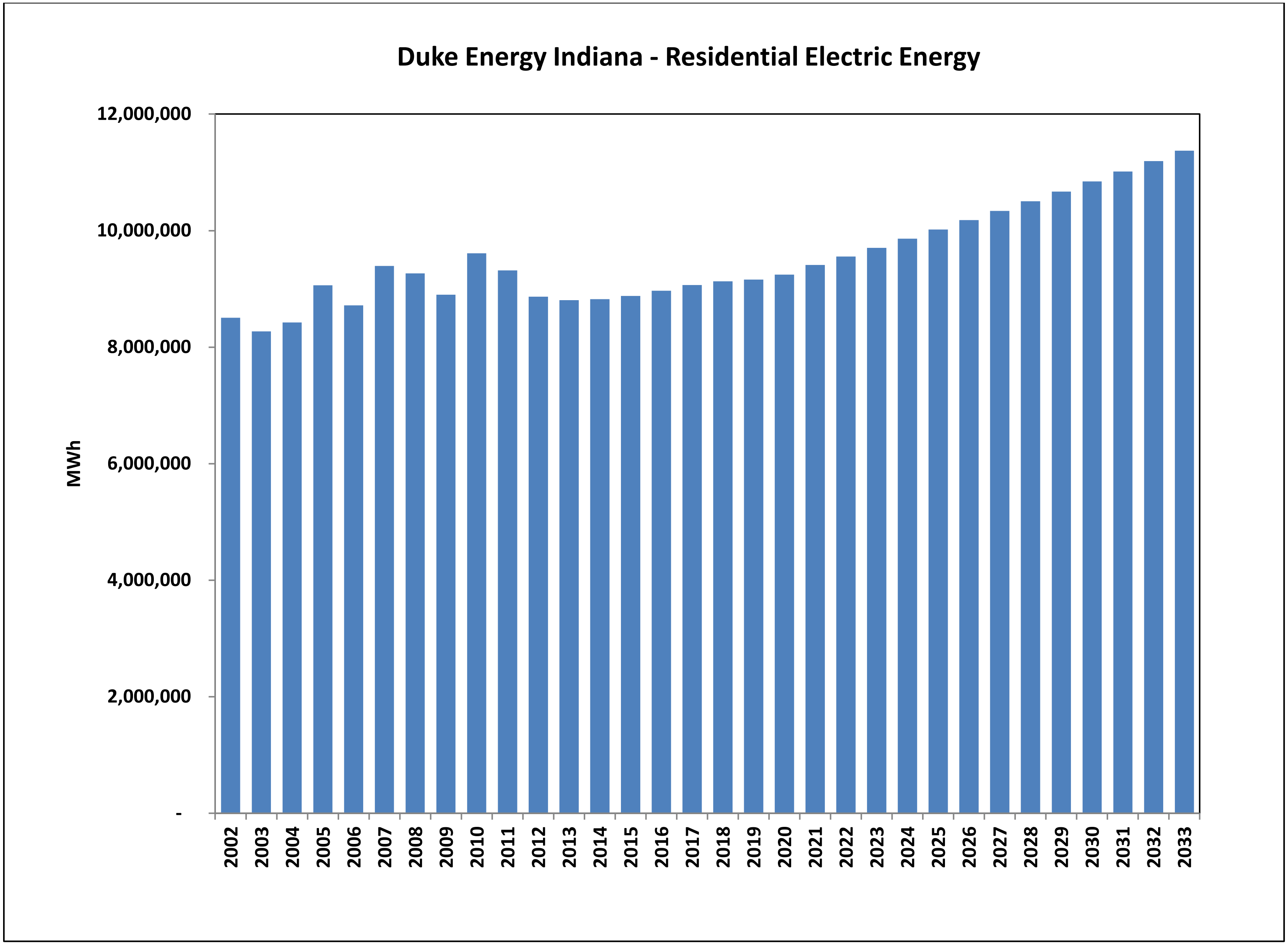
Month	Day	Year	Hr 1&13	Hr 2&14	Hr 3&15	Hr 4&16	Hr 5&17	Hr 6&18	Hr 7&19	Hr 8&20	Hr 9&21	Hr 10&22	Hr 11&23	Hr 12&24
10	1	2012	2,493	2,440	2,461	2,493	2,687	3,267	3,525	3,522	3,565	3,636	3,666	3,698
10	1	2012	3,726	3,643	3,605	3,568	3,504	3,591	3,695	3,737	3,599	3,315	3,163	2,830
10	2	2012	2,675	2,689	2,678	2,702	2,778	3,099	3,594	3,668	3,704	3,737	3,695	3,720
10	2	2012	3,741	3,640	3,609	3,585	3,603	3,618	3,711	3,752	3,632	3,338	2,930	2,801
10	3	2012	2,708	2,688	2,630	2,663	2,817	3,071	3,514	3,588	3,586	3,646	3,631	3,623
10	3	2012	3,594	3,600	3,602	3,610	3,603	3,637	3,694	3,853	3,636	3,392	2,969	2,828
10	4	2012	2,688	2,675	2,604	2,659	2,845	3,423	3,613	3,578	3,655	3,752	3,757	3,801
10	4	2012	3,889	3,913	3,853	3,835	3,827	3,740	3,770	3,896	3,760	3,494	3,182	3,048
10	5	2012	2,732	2,657	2,614	2,651	2,974	3,333	3,546	3,499	3,551	3,653	3,665	3,664
10	5	2012	3,684	3,648	3,602	3,571	3,604	3,554	3,557	3,613	3,491	3,279	3,074	2,925
10	6	2012	2,818	2,781	2,745	2,782	2,830	2,989	3,207	3,300	3,369	3,357	3,305	3,262
10	6	2012	3,201	3,145	3,063	3,080	3,098	3,134	3,285	3,328	3,221	3,108	2,952	2,800
10	7	2012	2,736	2,691	2,667	2,688	2,673	2,871	3,005	3,095	3,208	3,255	3,211	3,234
10	7	2012	3,209	3,192	3,120	3,101	3,173	3,230	3,391	3,475	3,394	3,258	3,130	2,982
10	8	2012	2,775	2,782	2,785	2,866	3,277	3,681	3,942	3,970	3,959	3,954	3,850	3,791
10	8	2012	3,803	3,721	3,653	3,535	3,444	3,576	3,693	3,788	3,670	3,445	3,313	3,219
10	9	2012	2,915	2,903	2,868	2,963	3,119	3,465	3,695	3,638	3,884	3,827	3,697	3,651
10	9	2012	3,634	3,581	3,526	3,482	3,504	3,536	3,670	3,766	3,582	3,393	2,965	2,839
10	10	2012	2,774	2,756	2,740	2,808	2,839	3,176	3,402	3,369	3,580	3,593	3,520	3,514
10	10	2012	3,499	3,450	3,402	3,367	3,436	3,522	3,708	4,251	4,086	3,759	3,610	3,263
10	11	2012	2,923	2,866	2,875	2,941	3,126	3,732	4,086	3,979	3,924	3,932	3,812	3,811
10	11	2012	3,689	3,681	3,595	3,571	3,551	3,564	3,659	3,780	3,705	3,258	3,050	2,936
10	12	2012	2,857	2,808	2,793	2,855	3,003	3,567	3,817	3,808	3,800	3,806	3,703	3,683
10	12	2012	3,659	3,618	3,518	3,482	3,423	3,387	3,424	3,551	3,493	3,331	2,882	2,772
10	13	2012	2,664	2,651	2,624	2,630	2,932	3,112	3,274	3,339	3,440	3,415	3,388	3,314
10	13	2012	3,289	3,299	3,294	3,323	3,297	3,305	3,389	3,438	3,318	3,136	2,956	2,852
10	14	2012	2,579	2,453	2,444	2,354	2,678	2,829	2,982	3,027	3,101	3,200	3,211	3,271
10	14	2012	3,348	3,297	3,282	3,266	3,347	3,369	3,495	3,519	3,391	3,111	2,959	2,863
10	15	2012	2,901	2,794	2,852	2,900	3,058	3,715	4,029	4,055	4,095	4,179	4,084	4,118
10	15	2012	4,065	4,052	3,999	3,991	3,948	3,934	4,100	4,120	4,002	3,713	3,457	3,145
10	16	2012	3,052	2,980	3,019	3,090	3,271	3,947	4,218	4,226	4,143	4,141	4,180	4,127
10	16	2012	4,093	3,981	3,919	3,887	3,914	3,946	4,108	4,181	3,976	3,707	3,522	3,352
10	17	2012	3,057	2,932	2,858	2,990	3,342	3,791	4,067	4,069	4,091	4,078	4,134	4,145
10	17	2012	4,183	4,135	4,071	4,078	4,062	4,015	4,173	4,187	4,047	3,774	3,519	3,381
10	18	2012	3,086	3,005	2,996	2,975	3,320	3,799	4,058	4,065	4,070	4,119	4,089	4,060
10	18	2012	4,093	4,044	4,038	3,975	3,949	3,965	4,146	4,196	4,066	3,846	3,590	3,425
10	19	2012	3,125	3,083	2,993	3,053	3,458	3,821	4,083	4,104	4,114	4,086	4,073	4,109
10	19	2012	4,117	4,096	4,014	4,013	3,991	4,044	4,059	4,093	4,011	3,836	3,601	3,418
10	20	2012	3,140	3,019	3,013	3,044	3,092	3,302	3,506	3,577	3,832	3,859	3,898	3,830
10	20	2012	3,803	3,765	3,665	3,652	3,602	3,690	3,828	3,795	3,698	3,641	3,174	3,081
10	21	2012	2,921	3,002	2,955	2,966	3,004	3,154	3,259	3,405	3,672	3,673	3,679	3,649
10	21	2012	3,615	3,561	3,570	3,589	3,626	3,677	3,852	3,940	3,758	3,515	3,071	2,952
10	22	2012	2,910	2,891	2,842	2,859	3,209	3,641	3,923	3,947	4,005	4,081	4,055	4,107
10	22	2012	4,127	4,102	4,051	4,021	4,003	4,030	4,138	4,152	3,988	3,748	3,420	3,241
10	23	2012	2,795	2,630	2,688	2,722	2,873	3,383	3,676	3,699	3,710	3,762	3,755	3,799
10	23	2012	3,807	3,799	3,743	3,700	3,673	3,707	3,833	3,844	3,693	3,471	3,250	3,071
10	24	2012	2,791	2,701	2,687	2,737	3,078	3,698	3,943	3,913	3,943	4,036	4,085	4,135
10	24	2012	4,196	4,214	4,233	4,223	4,198	4,156	4,274	4,266	4,102	3,877	3,316	3,152
10	25	2012	2,793	2,738	2,638	2,700	2,865	3,665	3,951	3,967	4,005	4,076	4,094	4,172
10	25	2012	4,204	4,231	4,193	4,171	4,117	4,100	4,213	4,188	4,029	3,768	3,058	2,865
10	26	2012	2,723	2,590	2,545	2,667	2,776	3,569	3,816	3,871	3,937	3,977	3,986	3,995
10	26	2012	3,988	3,949	3,906	3,893	3,872	3,880	3,960	3,820	3,843	3,506	3,217	3,070
10	27	2012	2,961	2,913	2,892	2,917	2,983	3,105	3,392	3,513	3,578	3,581	3,534	3,472
10	27	2012	3,408	3,287	3,156	3,356	3,394	3,513	3,667	3,704	3,404	3,250	3,068	2,934
10	28	2012	2,873	2,831	2,826	2,849	2,904	3,004	3,156	3,230	3,424	3,453	3,462	3,361
10	28	2012	3,312	3,237	3,251	3,313	3,418	3,764	3,982	3,953	3,853	3,431	3,239	3,144
10	29	2012	3,076	3,113	3,112	3,220	3,431	4,132	4,484	4,487	4,469	4,476	4,407	4,307
10	29	2012	4,273	4,217	4,132	4,120	4,156	4,264	4,414	4,415	4,258	3,739	3,456	3,364
10	30	2012	3,312	3,251	3,239	3,304	3,471	4,152	4,467	4,457	4,486	4,506	4,519	4,468
10	30	2012	4,486	4,428	4,384	4,356	4,361	4,407	4,469	4,463	4,376	3,946	3,587	3,473
10	31	2012	3,373	3,334	3,306	3,394	3,539	4,277	4,539	4,551	4,563	4,536	4,495	4,442
10	31	2012	4,413	4,327	4,199	4,168	4,149	4,205	4,342	4,337	4,256	3,839	3,538	3,386

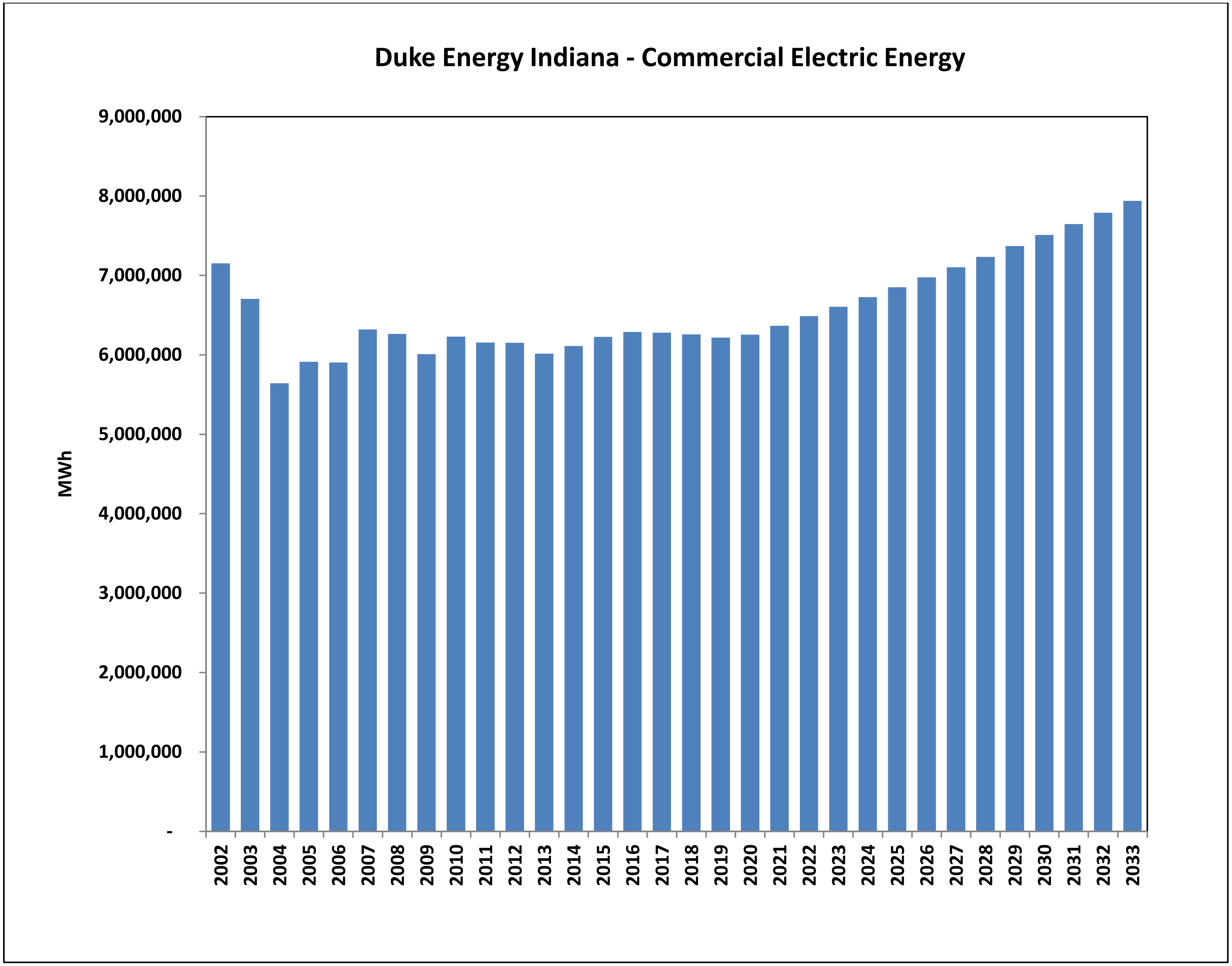
Month	Day	Year	Hr 1&13	Hr 2&14	Hr 3&15	Hr 4&16	Hr 5&17	Hr 6&18	Hr 7&19	Hr 8&20	Hr 9&21	Hr 10&22	Hr 11&23	Hr 12&24
11	1	2012	3,518	3,500	3,498	3,590	3,769	4,290	4,628	4,604	4,521	4,504	4,415	4,334
11	1	2012	4,308	4,228	4,143	4,077	4,120	4,286	4,309	4,307	4,195	3,955	3,832	3,658
11	2	2012	3,307	3,265	3,295	3,349	3,534	4,188	4,469	4,522	4,452	4,385	4,227	4,229
11	2	2012	4,180	4,167	4,035	3,999	3,966	4,056	4,187	4,225	4,119	3,998	3,543	3,357
11	3	2012	3,349	3,295	3,301	3,317	3,425	3,705	3,837	4,132	4,190	4,230	4,275	4,267
11	3	2012	4,204	4,127	4,006	4,071	4,041	4,127	4,153	4,133	4,096	3,948	3,551	3,335
11	4	2012	3,286	3,251	3,284	3,261	3,283	3,348	3,474	3,918	4,105	4,059	3,972	3,724
11	4	2012	3,734	3,651	3,648	3,613	3,763	4,053	4,215	4,247	4,220	4,070	3,673	3,543
11	5	2012	3,531	3,462	3,510	3,563	3,678	4,230	4,630	4,782	4,735	4,607	4,556	4,442
11	5	2012	4,382	4,402	4,332	4,244	4,218	4,358	4,547	4,582	4,522	4,376	3,902	3,697
11	6	2012	3,627	3,533	3,508	3,529	3,650	4,171	4,553	4,674	4,640	4,543	4,483	4,348
11	6	2012	4,301	4,297	4,282	4,205	4,215	4,406	4,528	4,353	4,284	4,138	3,732	3,457
11	7	2012	3,407	3,305	3,328	3,307	3,425	3,866	4,144	4,333	4,322	4,304	4,353	4,251
11	7	2012	4,187	4,182	4,098	4,062	4,117	4,301	4,455	4,414	4,394	4,346	3,852	3,608
11	8	2012	3,408	3,399	3,379	3,410	3,578	4,069	4,448	4,611	4,603	4,584	4,482	4,422
11	8	2012	4,335	4,358	4,239	4,134	4,218	4,305	4,518	4,528	4,482	4,395	4,008	3,643
11	9	2012	3,562	3,420	3,452	3,427	3,589	4,064	4,459	4,556	4,507	4,370	4,290	4,242
11	9	2012	4,145	4,166	4,074	4,036	4,005	4,061	4,140	4,019	3,973	3,922	3,568	3,239
11	10	2012	3,146	3,198	2,901	2,928	2,896	3,032	3,406	3,650	3,698	3,795	3,763	3,723
11	10	2012	3,638	3,325	3,297	3,247	3,271	3,643	3,804	3,782	3,708	3,315	3,136	2,974
11	11	2012	2,884	2,737	2,714	2,722	2,683	2,792	2,892	2,985	3,286	3,399	3,468	3,463
11	11	2012	3,282	3,251	3,221	3,235	3,241	3,750	3,910	3,915	3,846	3,581	3,187	3,034
11	12	2012	3,030	2,882	2,850	2,853	2,917	3,369	3,811	4,069	4,159	4,216	4,298	4,268
11	12	2012	4,214	4,208	4,128	4,077	4,133	4,368	4,587	4,625	4,567	4,404	3,979	3,816
11	13	2012	3,673	3,611	3,600	3,582	3,628	4,161	4,565	4,724	4,693	4,581	4,511	4,392
11	13	2012	4,353	4,372	4,286	4,213	4,209	4,425	4,612	4,665	4,563	4,496	4,136	3,905
11	14	2012	3,730	3,719	3,682	3,745	3,851	4,317	4,644	4,704	4,644	4,596	4,518	4,399
11	14	2012	4,313	4,249	4,206	4,152	4,263	4,510	4,670	4,712	4,618	4,542	4,337	3,954
11	15	2012	3,800	3,720	3,730	3,769	3,838	4,304	4,673	4,868	4,801	4,717	4,600	4,484
11	15	2012	4,427	4,395	4,269	4,184	4,203	4,349	4,559	4,629	4,578	4,502	4,079	3,926
11	16	2012	3,817	3,710	3,649	3,706	3,842	4,317	4,605	4,827	4,724	4,586	4,521	4,343
11	16	2012	4,305	4,231	4,047	3,943	3,942	4,169	4,368	4,301	4,285	4,139	3,786	3,621
11	17	2012	3,458	3,484	3,447	3,438	3,520	3,660	3,887	4,198	4,313	4,182	4,114	4,011
11	17	2012	3,708	3,619	3,512	3,445	3,513	3,834	4,008	4,013	3,985	3,726	3,563	3,418
11	18	2012	3,291	3,264	3,200	3,226	3,277	3,363	3,460	3,635	3,695	3,691	3,654	3,566
11	18	2012	3,461	3,355	3,361	3,300	3,352	3,838	3,958	3,997	4,052	3,725	3,595	3,452
11	19	2012	3,252	3,237	3,263	3,291	3,359	3,797	4,216	4,444	4,492	4,430	4,424	4,302
11	19	2012	4,278	4,262	4,162	4,128	4,099	4,232	4,382	4,314	4,300	4,178	3,754	3,491
11	20	2012	3,287	3,180	3,206	3,204	3,238	3,610	4,067	4,288	4,322	4,299	4,238	4,198
11	20	2012	4,199	4,197	4,192	4,173	4,116	4,265	4,342	4,270	4,194	4,045	3,589	3,367
11	21	2012	3,238	3,109	3,084	3,051	3,136	3,403	3,945	4,069	4,105	4,125	4,082	4,020
11	21	2012	3,973	3,968	3,896	3,807	3,807	3,974	4,138	4,099	4,008	3,741	3,454	3,155
11	22	2012	3,063	2,999	2,953	2,825	2,906	3,062	3,111	3,204	3,318	3,401	3,541	3,325
11	22	2012	3,180	3,002	2,822	2,814	2,801	3,101	3,211	3,247	3,183	2,904	2,911	2,814
11	23	2012	2,757	2,690	2,646	2,553	2,713	2,803	2,989	3,113	3,266	3,396	3,476	3,465
11	23	2012	3,446	3,469	3,523	3,529	3,658	4,023	4,123	4,072	4,104	3,852	3,709	3,510
11	24	2012	3,390	3,371	3,211	3,290	3,265	3,494	3,663	3,795	4,087	4,192	4,290	4,255
11	24	2012	3,915	3,839	3,771	3,719	3,789	4,227	4,348	4,349	4,315	4,039	3,972	3,754
11	25	2012	3,563	3,480	3,412	3,427	3,435	3,490	3,703	3,798	3,795	3,930	3,888	3,816
11	25	2012	3,749	3,575	3,537	3,493	3,889	4,061	4,237	4,216	4,200	3,903	3,744	3,622
11	26	2012	3,422	3,291	3,347	3,349	3,450	4,012	4,457	4,660	4,643	4,543	4,466	4,408
11	26	2012	4,368	4,184	4,119	4,177	4,250	4,471	4,595	4,596	4,530	4,417	4,024	3,830
11	27	2012	3,602	3,538	3,479	3,476	3,597	4,041	4,507	4,726	4,678	4,627	4,577	4,562
11	27	2012	4,438	4,251	4,159	4,113	4,273	4,462	4,763	4,774	4,751	4,674	4,146	3,915
11	28	2012	4,104	3,990	3,807	3,794	3,944	4,344	4,627	4,857	4,723	4,614	4,517	4,393
11	28	2012	4,312	4,254	4,163	4,089	4,136	4,447	4,670	4,706	4,723	4,631	4,397	4,199
11	29	2012	3,920	3,876	3,837	3,838	3,970	4,374	4,626	4,866	4,804	4,701	4,573	4,484
11	29	2012	4,506	4,351	4,264	4,149	4,229	4,433	4,552	4,493	4,579	4,436	4,070	3,829
11	30	2012	3,603	3,538	3,494	3,501	3,605	4,067	4,347	4,519	4,481	4,347	4,330	4,247
11	30	2012	4,175	4,146	3,853	3,793	3,736	4,148	4,263	4,220	4,208	4,122	3,827	3,497

Month	Day	Year	Hr 1&13	Hr 2&14	Hr 3&15	Hr 4&16	Hr 5&17	Hr 6&18	Hr 7&19	Hr 8&20	Hr 9&21	Hr 10&22	Hr 11&23	Hr 12&24
12	1	2012	3,293	3,103	3,045	3,011	3,084	3,156	3,397	3,714	3,788	3,891	3,990	3,881
12	1	2012	3,517	3,431	3,340	3,327	3,370	3,909	3,966	3,968	3,925	3,604	3,274	3,130
12	2	2012	2,972	2,901	2,782	2,776	2,792	2,808	2,977	3,096	3,195	3,320	3,422	3,424
12	2	2012	3,437	3,412	3,334	3,350	3,383	3,954	4,057	4,052	3,956	3,575	3,289	3,123
12	3	2012	3,013	2,949	2,900	2,828	2,930	3,168	3,858	4,134	4,137	4,112	4,136	4,145
12	3	2012	4,177	4,125	4,135	4,051	4,047	4,245	4,416	4,388	4,345	4,145	3,598	3,348
12	4	2012	3,123	3,012	2,893	2,924	2,995	3,344	3,841	4,098	4,107	4,119	4,166	4,184
12	4	2012	4,146	4,072	4,076	4,029	4,107	4,350	4,493	4,474	4,453	4,352	3,801	3,481
12	5	2012	3,373	3,276	3,235	3,261	3,279	3,771	4,182	4,460	4,411	4,308	4,235	4,174
12	5	2012	4,079	4,017	3,905	3,866	3,946	4,376	4,595	4,623	4,610	4,561	4,059	3,757
12	6	2012	3,687	3,566	3,516	3,556	3,536	4,108	4,570	4,777	4,704	4,742	4,687	4,577
12	6	2012	4,509	4,430	4,406	4,373	4,393	4,549	4,679	4,561	4,558	4,456	4,005	3,626
12	7	2012	3,450	3,300	3,239	3,207	3,268	3,793	4,140	4,341	4,377	4,378	4,384	4,396
12	7	2012	4,371	4,363	4,306	4,294	4,288	4,405	4,449	4,350	4,278	4,223	3,814	3,510
12	8	2012	3,435	3,281	3,209	3,172	3,149	3,280	3,454	3,807	3,888	4,027	4,026	4,005
12	8	2012	3,857	3,853	3,772	3,775	3,859	4,141	4,271	4,167	4,125	3,847	3,679	3,507
12	9	2012	3,297	3,169	3,135	3,059	3,117	3,180	3,276	3,497	3,610	3,705	3,739	3,780
12	9	2012	3,808	3,766	3,700	3,711	3,822	4,199	4,253	4,185	4,168	3,847	3,681	3,467
12	10	2012	3,223	3,153	3,163	3,151	3,312	3,813	4,176	4,433	4,478	4,537	4,571	4,654
12	10	2012	4,700	4,644	4,695	4,691	4,805	4,919	5,019	4,934	4,921	4,791	4,554	4,102
12	11	2012	3,981	3,821	3,746	3,756	4,035	4,239	4,637	4,863	4,831	4,837	4,781	4,744
12	11	2012	4,645	4,610	4,596	4,494	4,520	4,739	4,977	4,992	4,943	4,843	4,611	4,319
12	12	2012	4,121	4,075	3,946	3,944	4,235	4,537	4,735	4,877	4,774	4,678	4,566	4,429
12	12	2012	4,310	4,261	4,180	4,128	4,188	4,484	4,655	4,739	4,768	4,709	4,539	4,372
12	13	2012	4,203	3,948	3,974	3,997	4,173	4,386	4,781	4,987	4,905	4,822	4,705	4,579
12	13	2012	4,521	4,479	4,344	4,250	4,250	4,480	4,711	4,732	4,708	4,650	4,406	4,241
12	14	2012	3,840	3,788	3,733	3,734	3,801	4,262	4,567	4,727	4,680	4,559	4,442	4,356
12	14	2012	4,239	4,225	4,196	4,087	4,189	4,393	4,483	4,457	4,413	4,314	4,177	3,663
12	15	2012	3,449	3,347	3,282	3,178	3,235	3,279	3,759	4,017	4,072	4,195	4,249	4,233
12	15	2012	4,179	4,119	4,047	4,009	4,009	4,144	4,188	4,124	4,098	3,995	3,573	3,250
12	16	2012	3,054	2,941	2,877	2,861	2,872	2,921	2,974	3,082	3,427	3,601	3,597	3,642
12	16	2012	3,407	3,376	3,355	3,395	3,797	4,006	4,126	4,146	4,153	4,070	3,779	3,447
12	17	2012	3,220	3,128	3,091	3,160	3,214	3,476	4,168	4,407	4,450	4,427	4,480	4,452
12	17	2012	4,379	4,434	4,429	4,345	4,404	4,525	4,627	4,613	4,613	4,414	4,216	3,822
12	18	2012	3,527	3,391	3,361	3,396	3,447	3,871	4,315	4,571	4,544	4,529	4,556	4,554
12	18	2012	4,552	4,529	4,414	4,379	4,360	4,459	4,628	4,640	4,669	4,521	4,261	3,686
12	19	2012	3,527	3,478	3,421	3,413	3,480	3,966	4,430	4,537	4,483	4,476	4,442	4,364
12	19	2012	4,312	4,248	4,153	4,061	4,172	4,378	4,482	4,562	4,502	4,457	4,080	3,591
12	20	2012	3,472	3,344	3,277	3,218	3,318	3,517	4,203	4,432	4,493	4,383	4,392	4,422
12	20	2012	4,385	4,351	4,357	4,378	4,455	4,717	4,866	4,843	4,832	4,768	4,575	4,030
12	21	2012	3,875	3,799	3,808	3,779	3,888	4,167	4,686	4,703	4,983	4,947	5,040	5,051
12	21	2012	5,021	4,977	4,860	4,822	4,863	4,979	5,071	5,032	4,893	4,803	4,595	4,362
12	22	2012	4,123	4,022	3,913	3,769	3,792	4,129	4,288	4,524	4,578	4,567	4,530	4,431
12	22	2012	4,278	4,154	4,035	4,019	4,029	4,268	4,500	4,508	4,509	4,447	4,340	3,938
12	23	2012	3,667	3,550	3,480	3,452	3,464	3,543	3,709	3,935	4,265	4,228	4,105	3,988
12	23	2012	3,877	3,773	3,686	3,410	3,712	3,975	4,180	4,196	4,242	4,134	3,994	3,615
12	24	2012	3,389	3,309	3,224	3,165	3,172	3,208	3,237	3,650	3,731	3,889	3,949	3,907
12	24	2012	3,812	3,506	3,426	3,383	3,460	3,895	3,919	3,609	3,532	3,452	3,360	3,166
12	25	2012	3,067	2,989	2,932	2,902	2,925	2,989	3,074	3,272	3,562	3,628	3,497	3,486
12	25	2012	3,413	3,322	3,291	3,277	3,314	3,767	3,920	3,900	3,894	3,832	3,495	3,291
12	26	2012	3,176	3,118	3,113	3,131	3,201	3,356	3,785	4,204	4,283	4,328	4,380	4,375
12	26	2012	4,374	4,329	4,272	4,234	4,273	4,420	4,551	4,498	4,421	4,277	4,091	3,861
12	27	2012	3,371	3,309	3,272	3,263	3,306	3,502	4,022	4,235	4,308	4,360	4,385	4,412
12	27	2012	4,318	4,303	4,276	4,313	4,327	4,443	4,587	4,491	4,476	4,400	4,206	3,798
12	28	2012	3,670	3,622	3,543	3,542	3,662	3,716	4,217	4,303	4,357	4,410	4,398	4,393
12	28	2012	4,398	4,383	4,349	4,325	4,379	4,448	4,558	4,478	4,408	4,373	4,205	3,839
12	29	2012	3,632	3,448	3,469	3,437	3,413	3,491	3,614	4,050	4,174	4,218	4,298	4,268
12	29	2012	4,274	4,097	4,071	4,031	4,114	4,492	4,582	4,611	4,536	4,419	4,070	3,955
12	30	2012	3,734	3,698	3,618	3,567	3,617	3,667	3,845	4,069	4,199	4,405	4,329	4,201
12	30	2012	3,931	3,782	3,746	3,739	3,876	4,295	4,475	4,470	4,455	4,355	3,998	3,840
12	31	2012	3,659	3,504	3,484	3,447	3,491	3,564	3,836	3,997	4,047	4,048	4,123	4,072
12	31	2012	4,047	4,040	4,054	3,981	3,987	4,347	4,396	4,298	4,124	3,789	3,708	3,614

3. Duke Energy Indiana Long-Term Electric Forecast

The following pages pertain to customer demand for electric energy within the Duke Energy Indiana service territory.


Duke Energy Indiana - Residential Electric Energy
MWh
12,000,000
10,000,000
8,000,000
6,000,000
4,000,000
2,000,000
-
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033


Duke Energy Indiana - Commercial Electric Energy
MWh
9,000,000
8,000,000
7,000,000
6,000,000
5,000,000
4,000,000
3,000,000
2,000,000
1,000,000
-
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
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2026
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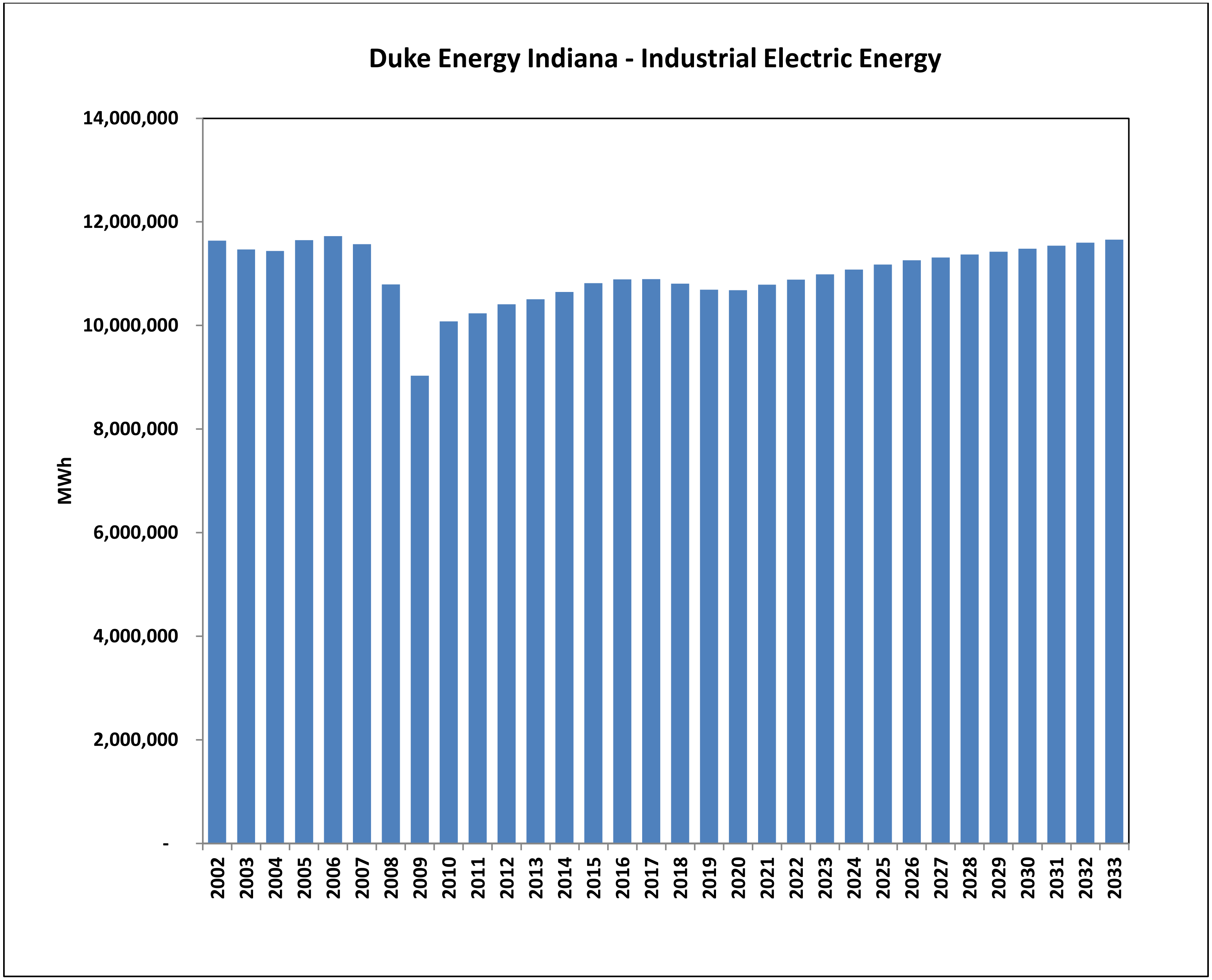
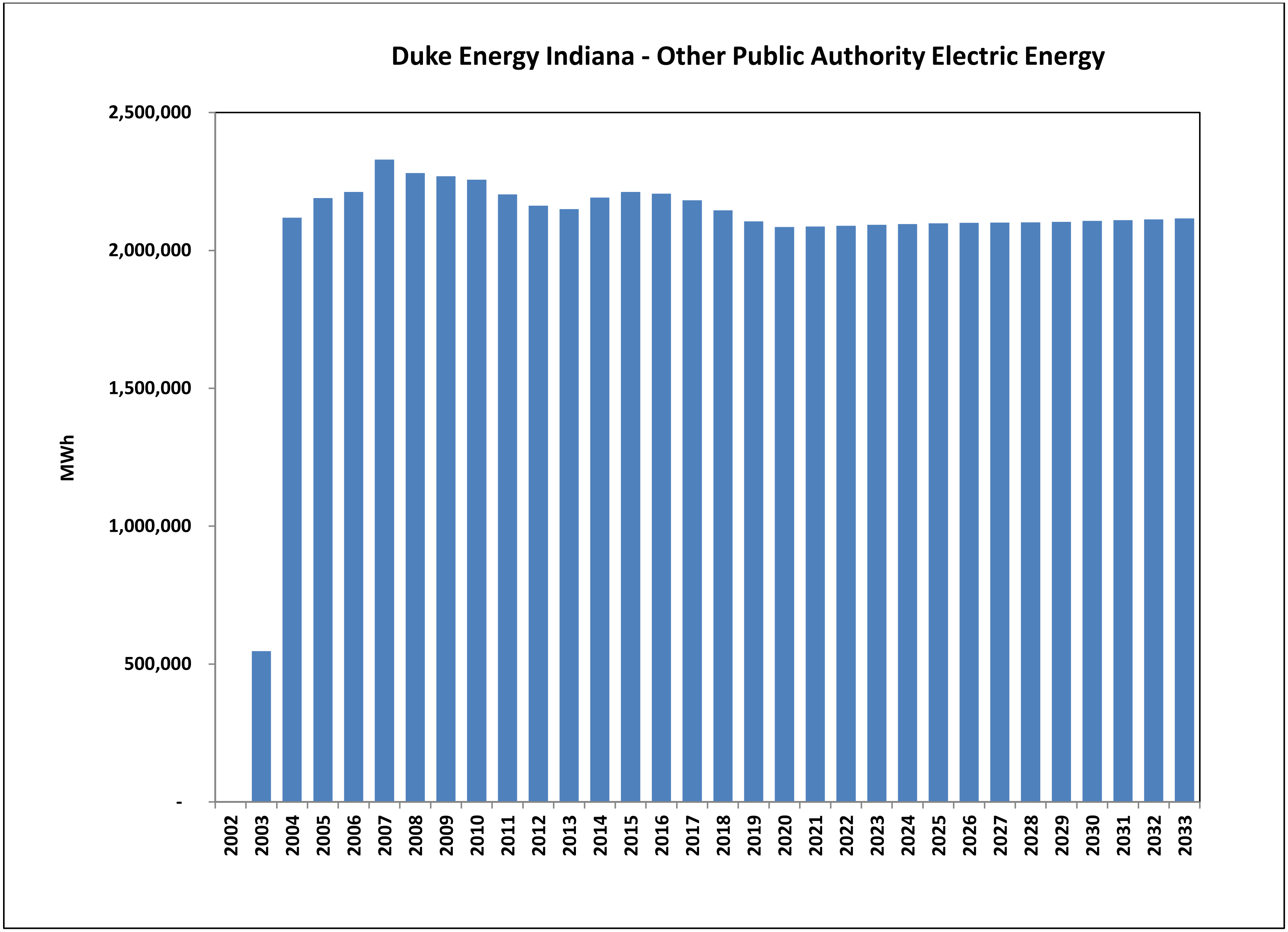
2029
2030
2031
2032
2033



Duke Energy Indiana - Industrial Electric Energy
14,000,000
12,000,000
10,000,000
8,000,000
6,000,000
4,000,000
2,000,000
-
MWh
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033


Duke Energy Indiana - Other Public Authority Electric Energy
MWh
2,500,000
2,000,000
1,500,000
1,000,000
500,000
-
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
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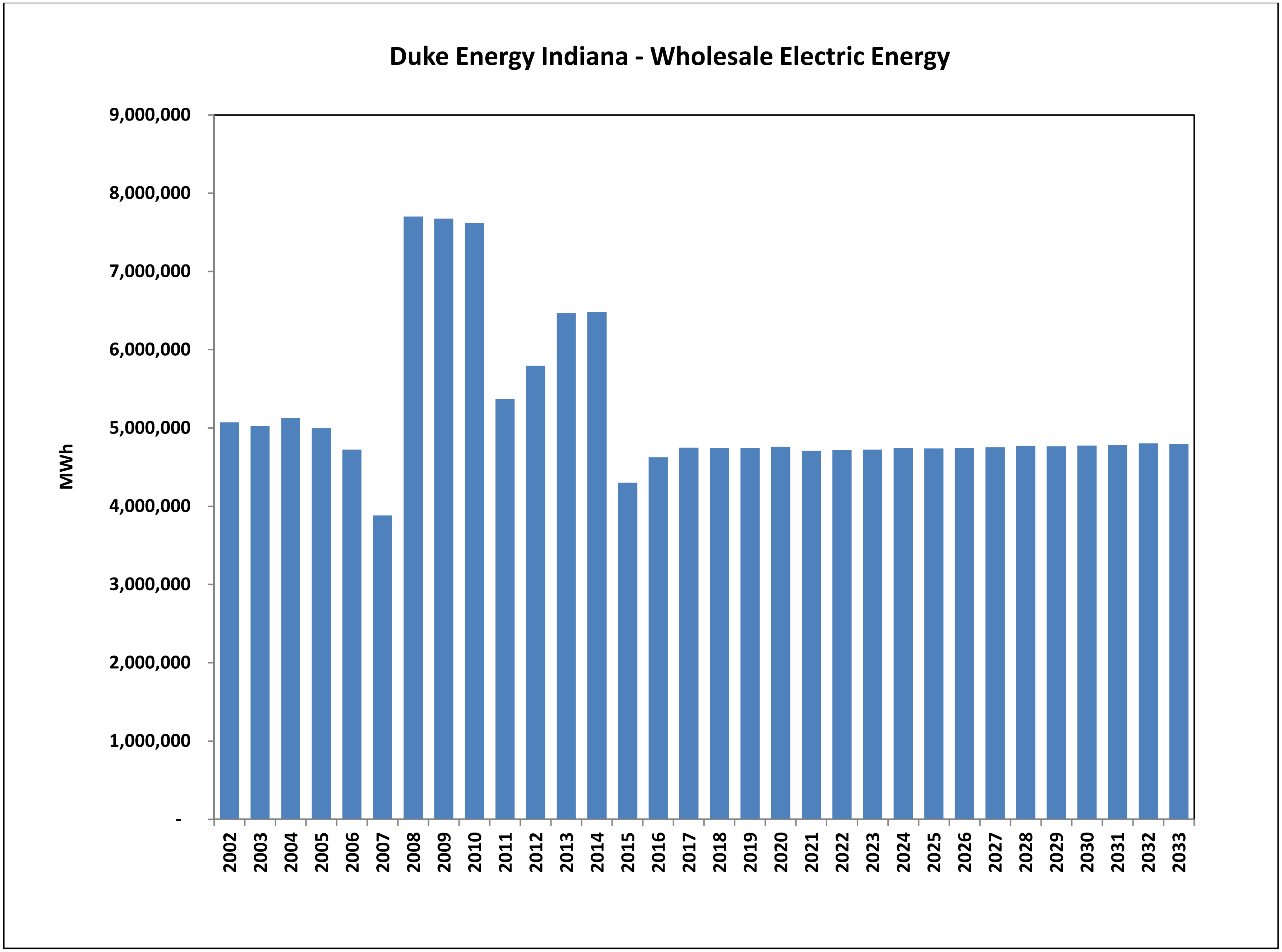
2029
2030
2031
2032
2033


Duke Energy Indiana - Wholesale Electric Energy
MWh
9,000,000
8,000,000
7,000,000
6,000,000
5,000,000
4,000,000
3,000,000
2,000,000
1,000,000
-
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
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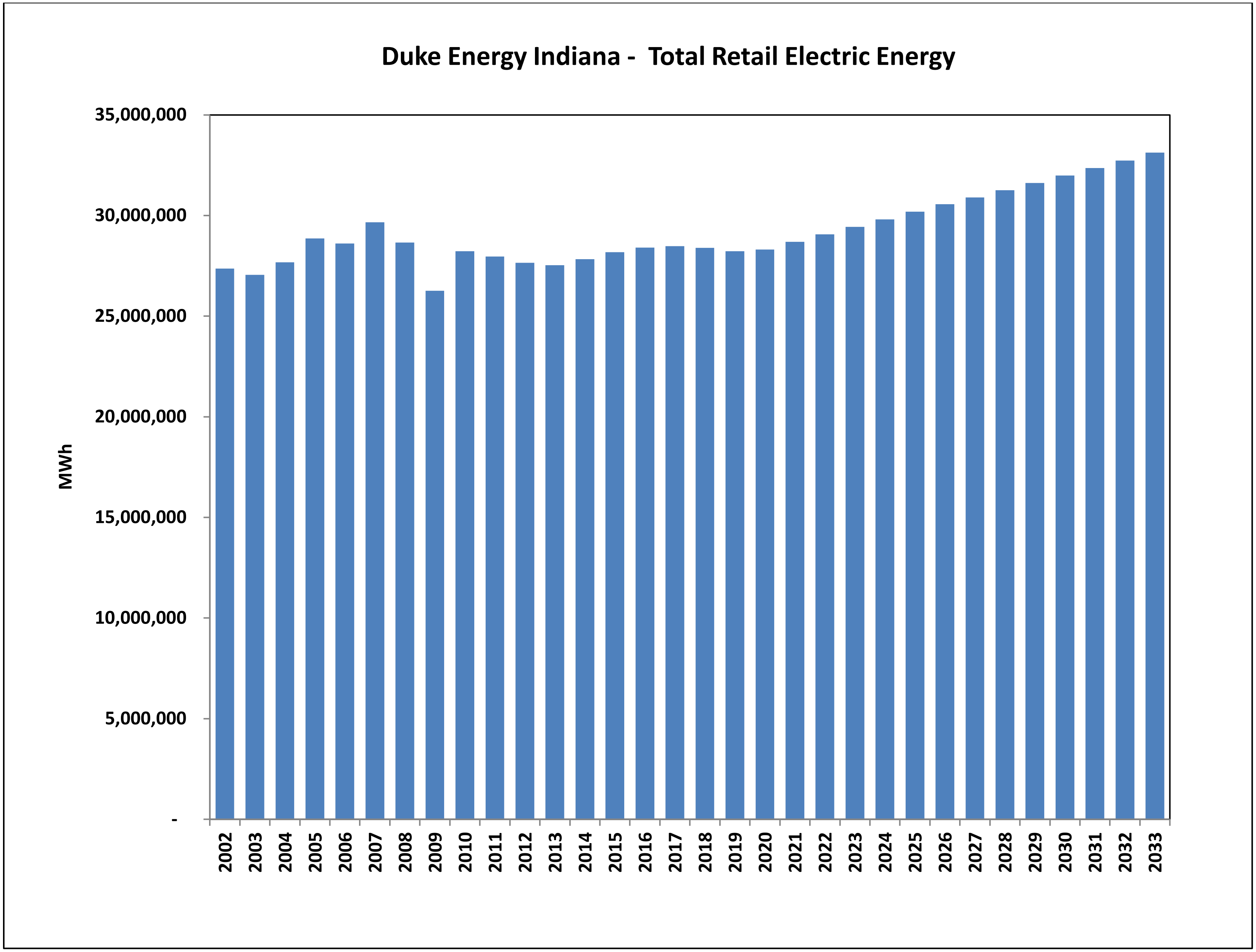
2032
2033


Duke Energy Indiana - Total Retail Electric Energy
MWh
35,000,000
30,000,000
25,000,000
20,000,000
15,000,000
10,000,000
5,000,000
-
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
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2029
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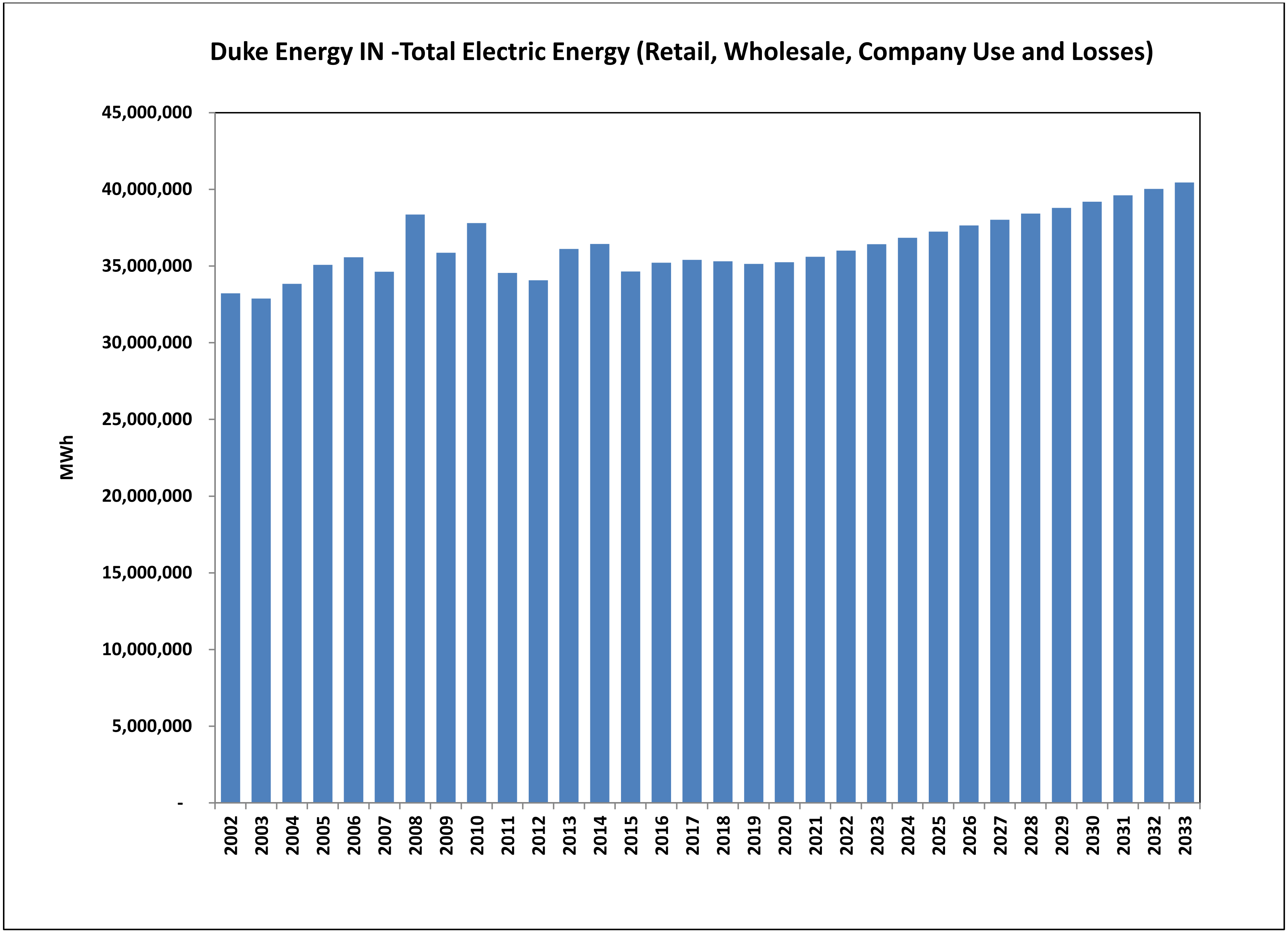
2031
2032
2033


Duke Energy IN -Total Electric Energy (Retail, Wholesale, Company Use and Losses)
MWh
45,000,000
40,000,000
35,000,000
30,000,000
25,000,000
20,000,000
15,000,000
10,000,000
5,000,000
-
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
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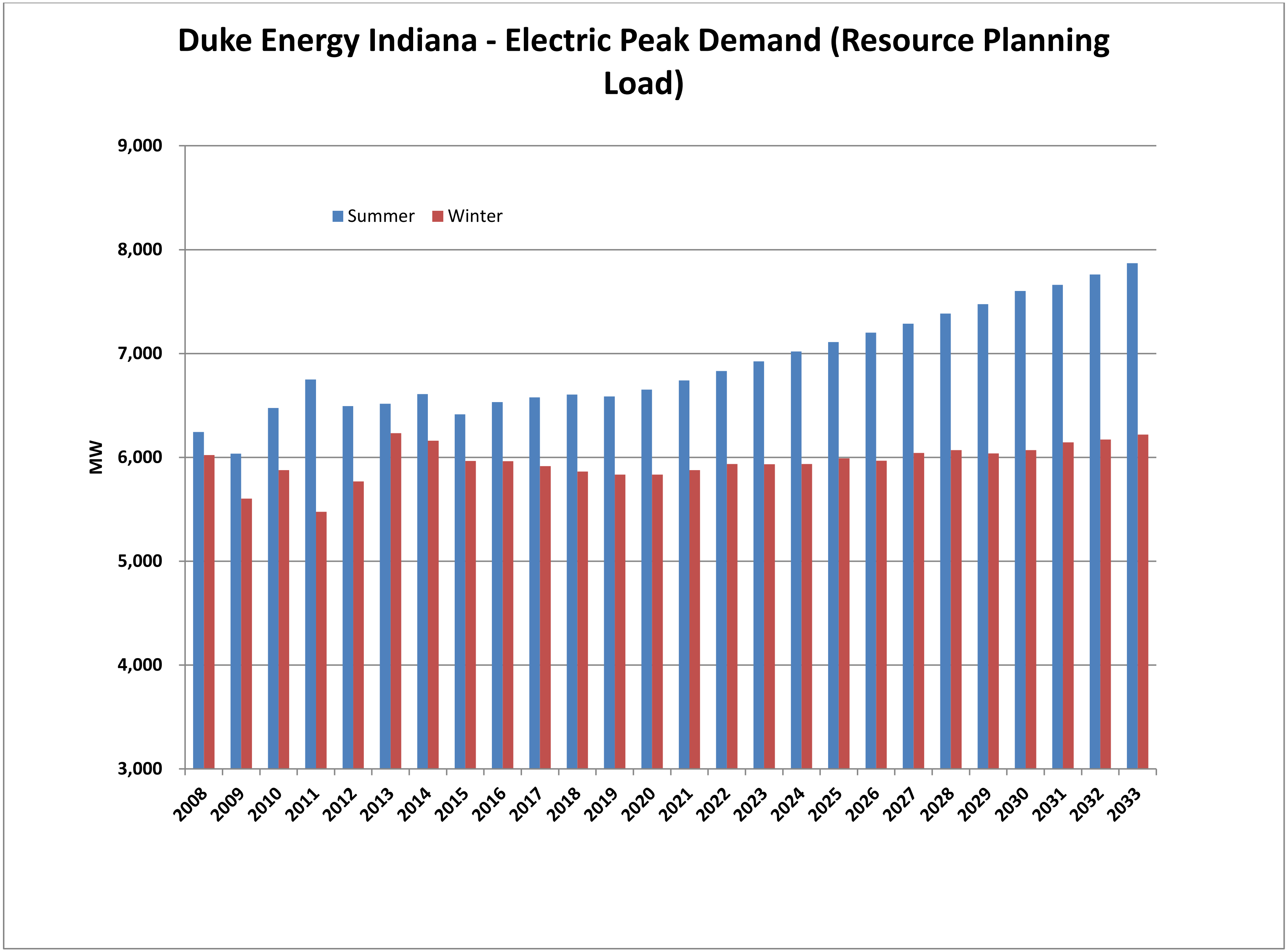
2031
2032
2033


Duke Energy Indiana - Electric Peak Demand (Resource Planning Load)
Summer
Winter
MW
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
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2026
2027
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2031
2032
2033

DUKE ENERGY INDIANA
ELECTRIC CUSTOMERS
ANNUAL AVERAGES

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET LIGHTING	O. P. A.	TOTAL CUSTOMERS	ANNUAL INCREASE	ELECTRIC - KWH RESIDENTIAL USE PER CUSTOMER
2006	665,217	87,575	2,884	1,095	9,394	766,166		13,107
2007	671,749	88,679	2,868	1,187	9,471	773,954	7,788	13,987
2008	673,412	89,544	2,842	1,261	9,586	776,646	2,692	13,762
2009	672,740	89,410	2,814	1,319	9,862	776,144	(501)	13,232
2010	677,998	89,554	2,790	1,358	10,119	781,819	5,675	14,173
2011	678,931	89,493	2,754	1,399	10,302	782,878	1,059	13,722
2012	683,335	89,861	2,734	1,433	10,259	787,621	4,742	12,977
2013	687,953	90,303	2,741	1,462	10,508	792,967	5,347	12,804
2014	695,884	91,304	2,763	1,486	10,624	802,060	9,093	12,680
2015	704,922	92,377	2,775	1,507	10,734	812,315	10,255	12,595
2016	715,210	93,654	2,786	1,525	10,842	824,016	11,701	12,542
2017	726,732	95,052	2,795	1,540	10,947	837,066	13,050	12,475
2018	737,511	96,322	2,801	1,553	11,049	849,235	12,169	12,380
2019	746,847	97,274	2,802	1,563	11,149	859,636	10,401	12,267
2020	755,132	97,962	2,801	1,572	11,250	868,718	9,082	12,241
2021	763,127	98,549	2,799	1,580	11,349	877,404	8,686	12,329
2022	771,023	99,120	2,797	1,588	11,445	885,973	8,569	12,391
2023	779,093	99,675	2,794	1,594	11,542	894,698	8,725	12,459
2024	787,290	100,184	2,790	1,600	11,637	903,502	8,804	12,527
2025	795,659	100,657	2,786	1,606	11,733	912,441	8,939	12,595
2026	803,836	101,106	2,782	1,612	11,826	921,161	8,721	12,663
2027	811,963	101,529	2,777	1,617	11,917	929,803	8,642	12,733
2028	820,239	101,930	2,772	1,622	12,008	938,571	8,768	12,804
2029	828,744	102,304	2,767	1,627	12,100	947,542	8,971	12,877
2030	837,365	102,661	2,761	1,632	12,192	956,611	9,069	12,948
2031	845,963	103,031	2,756	1,636	12,280	965,666	9,055	13,020
2032	854,803	103,431	2,750	1,641	12,368	974,993	9,327	13,093
2033	864,025	103,861	2,744	1,646	12,460	984,736	9,743	13,164
GROWTH RATE								
2013-2018	1.4%	1.3%	0.4%	1.2%	1.0%	1.4%		-0.7%
2013-2023	1.3%	1.0%	0.2%	0.9%	1.0%	1.3%		-0.3%
2013-2033	1.3%	0.8%	0.0%	0.6%	0.9%	1.2%		0.1%

4. Schedule for End-Use Surveys

In the residential sector, Duke Energy Indiana is currently on a three-year schedule for conducting residential customer end-use surveys. The most recent survey was conducted in late 2010 and a project was approved to conduct the 2013 survey during the Fall. The results of the 2010 survey were incorporated into the Company's 2013 forecast.

In the commercial sector, the last survey was conducted in 1991. There has been no formal survey work conducted in the industrial sector. This is due to the nature of the sector itself. The industrial sector is a heterogeneous mix of distinct operations. Even customers within the same NAICS (North American Industry Classification System) can exhibit significant differences in processes and energy use patterns. For this reason, a formal on-site census is the preferred method for gathering useful end-use information. Currently, Duke Energy Indiana has no plans to conduct a formal industrial end-use census. This may also be modified according to the information needs of the Duke Energy Indiana forecasting department and other departments.

5. Evaluation of Previous 10 Years of Forecasts

Tables are attached showing actual versus forecast for the previous ten years.

In general, the methodology, equations, and types of data used have remained consistent over the years. In addition, the IURC has passed judgment on the reasonableness of the forecast and the methodology several times. Finally, the State Utility Forecasting Group (SUFG), though using models quite distinct from Duke Energy Indiana's, has historically produced forecasts that are similar to Duke Energy Indiana's.

Duke Energy Indiana Sales Forecasts - Comparison to Actuals in Thousands of Megawatts

	Actual	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
2002												
Residential	8,506	8,299										
Commercial	7,153	7,153										
Industrial	11,636	11,573										
Other	69	69										
Sales for Resale	5,072	4,951										
Total Sales	32,436	32,045										
2003												
Residential	8,270	8,496	8,511									
Commercial	6,705	7,351	5,899									
Industrial	11,466	11,972	11,278									
Other	609	70	2,227									
Sales for Resale	5,030	5,043	5,072									
Total Sales	32,080	32,932	32,987									
2004												
Residential	8,423	8,683	8,763	8,772								
Commercial	5,642	7,493	6,053	6,079								
Industrial	11,437	12,216	11,515	11,900								
Other	2,171	70	2,282	2,109								
Sales for Resale	5,128	5,138	5,172	5,029								
Total Sales	32,801	33,600	33,785	33,889								
2005												
Residential	9,063	8,853	8,981	8,992	8,755							
Commercial	5,912	7,596	6,181	6,061	5,768							
Industrial	11,646	12,549	11,645	11,652	11,561							
Other	2,243	71	2,327	2,140	2,172							
Sales for Resale	4,997	4,940	5,019	4,867	4,772							
Total Sales	33,861	34,009	34,153	33,712	33,028							
2006												
Residential	8,719	9,026	9,158	9,273	8,940	9,069						
Commercial	5,903	7,717	6,316	6,202	5,935	5,847						
Industrial	11,727	12,721	11,871	11,810	11,712	11,954						
Other	2,266	72	2,377	2,188	2,247	2,259						
Sales for Resale	4,724	4,740	4,864	4,701	4,621	3,064						
Total Sales	33,339	34,276	34,586	34,174	33,455	32,193						
2007												
Residential	9,396	9,146	9,292	9,510	9,128	9,212	9,046					
Commercial	6,318	7,826	6,450	6,305	5,992	5,923	6,007					
Industrial	11,572	12,990	12,062	11,970	11,753	11,933	11,580					
Other	2,383	73	2,425	2,226	2,262	2,281	2,255					
Sales for Resale	3,881	3,848	4,074	3,947	2,962	1,548	7,690					
Total Sales	33,550	33,883	34,302	33,958	30,899	30,899	30,899					
2008												
Residential	9,267	9,328	9,483	9,708	9,294	9,322	9,162	9,092				
Commercial	6,263	7,966	6,564	6,397	6,053	6,006	6,077	6,277				
Industrial	10,792	13,298	12,227	12,139	11,793	11,952	11,486	11,411				
Other	2,335	74	2,466	2,260	2,275	2,307	2,273	2,402				
Sales for Resale	7,701	3,248	3,298	3,232	1,860	427	7,320	7,673				
Total Sales	36,358	33,914	34,038	33,736	30,015	30,015	30,015	30,015				
2009												
Residential	8,901	9,449	9,599	9,922	9,449	9,436	9,326	9,140	9,021			
Commercial	6,008	8,093	6,673	6,488	6,131	6,107	6,162	6,301	6,178			
Industrial	9,032	13,618	12,401	12,292	11,847	12,007	11,533	11,391	9,496			
Other	2,323	74	2,506	2,294	2,300	2,340	2,300	2,421	2,315			
Sales for Resale	7,675	3,027	3,062	3,232	1,880	433	7,327	7,695	7,597			
Total Sales	33,939	34,261	34,241	34,227	31,606	30,324	36,648	36,948	34,607			
2010												
Residential	9,609	9,585	9,739	10,092	9,615	9,546	9,482	9,244	8,863	9,094		
Commercial	6,229	8,214	6,783	6,568	6,204	6,204	6,253	6,362	6,156	5,974		
Industrial	10,082	13,944	12,619	12,434	11,900	12,050	11,654	11,400	9,824	9,236		
Other	2,310	75	2,548	2,323	2,324	2,371	2,332	2,431	2,291	2,352		
Sales for Resale	7,631	3,053	3,095	2,999	1,903	439	7,335	7,623	7,665	7,506		
Total Sales	35,861	34,871	34,784	34,416	31,946	30,610	37,056	37,059	34,799	34,162		
2011												
Residential	9,316	9,768	9,934	10,293	9,794	9,681	9,644	9,362	8,893	8,960	9,097	
Commercial	6,156	8,343	6,903	6,647	6,297	6,309	6,358	6,425	6,278	6,010	6,139	
Industrial	10,237	14,278	12,857	12,570	11,957	12,133	11,795	11,511	9,973	9,136	10,193	
Other	2,203	76	2,593	2,353	2,357	2,406	2,369	2,448	2,238	2,301	2,225	
Sales for Resale	5,370	2,650	2,650	3,021	1,924	446	7,343	7,585	7,675	7,486	7,081	
Total Sales	33,282	35,116	34,937	34,884	32,329	30,975	37,509	37,332	35,057	33,893	34,735	
2012												
Residential	8,867	9,946	10,122	10,618	9,979	9,832	9,803	9,279	8,958	8,943	9,098	8,945
Commercial	6,152	8,489	7,022	6,740	6,402	6,433	6,469	6,449	6,401	6,171	6,268	6,010
Industrial	10,411	14,624	13,093	12,705	12,018	12,245	11,948	11,571	10,016	9,147	10,244	10,358
Other	2,162	77	2,638	2,386	2,394	2,448	2,408	2,458	2,210	2,289	2,286	2,138
Sales for Resale	5,796	2,650	2,650	3,045	1,949	454	7,351	7,579	7,676	7,493	7,095	4,396
Total Sales	33,389	35,785	35,525	35,494	32,741	31,412	37,979	37,336	35,261	34,043	34,991	31,847

Forecasts reflect weather normal sales while actual show non-weather normal sales

Duke Energy Indiana Summer Peak Forecasts - Comparison to Actual in Megawatts

	Actual	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
2002	6,250	6,427										
2003	6,133	6,536	6,576									
2004	6,136	6,649	6,751	6,136								
2005	6,539	6,665	6,772	6,702	6,719							
2006	6,702	6,747	6,856	6,812	6,835	6,688						
2007	6,705	6,532	6,552	6,509	6,332	6,171	6,897					
2008	6,213	6,632	6,686	6,586	6,384	6,218	6,923	6,998				
2009	6,037	6,688	6,710	6,669	6,442	6,285	6,995	7,026	6,759			
2010	6,476	6,754	6,763	6,695	6,502	6,346	7,082	7,059	6,797	6,658		
2011	6,749	6,833	6,820	6,772	6,569	6,424	7,179	7,145	6,867	6,634	6,592	
2012	6,494	6,952	6,929	6,871	6,641	6,517	7,278	7,230	6,926	6,711	6,663	6,549
2013	6,023	7,061	7,028	6,855	6,711	6,608	7,373	7,294	6,956	6,811	6,772	6,610

Duke Energy Indiana Winter Peak Forecasts - Comparison to Actual in Megawatts

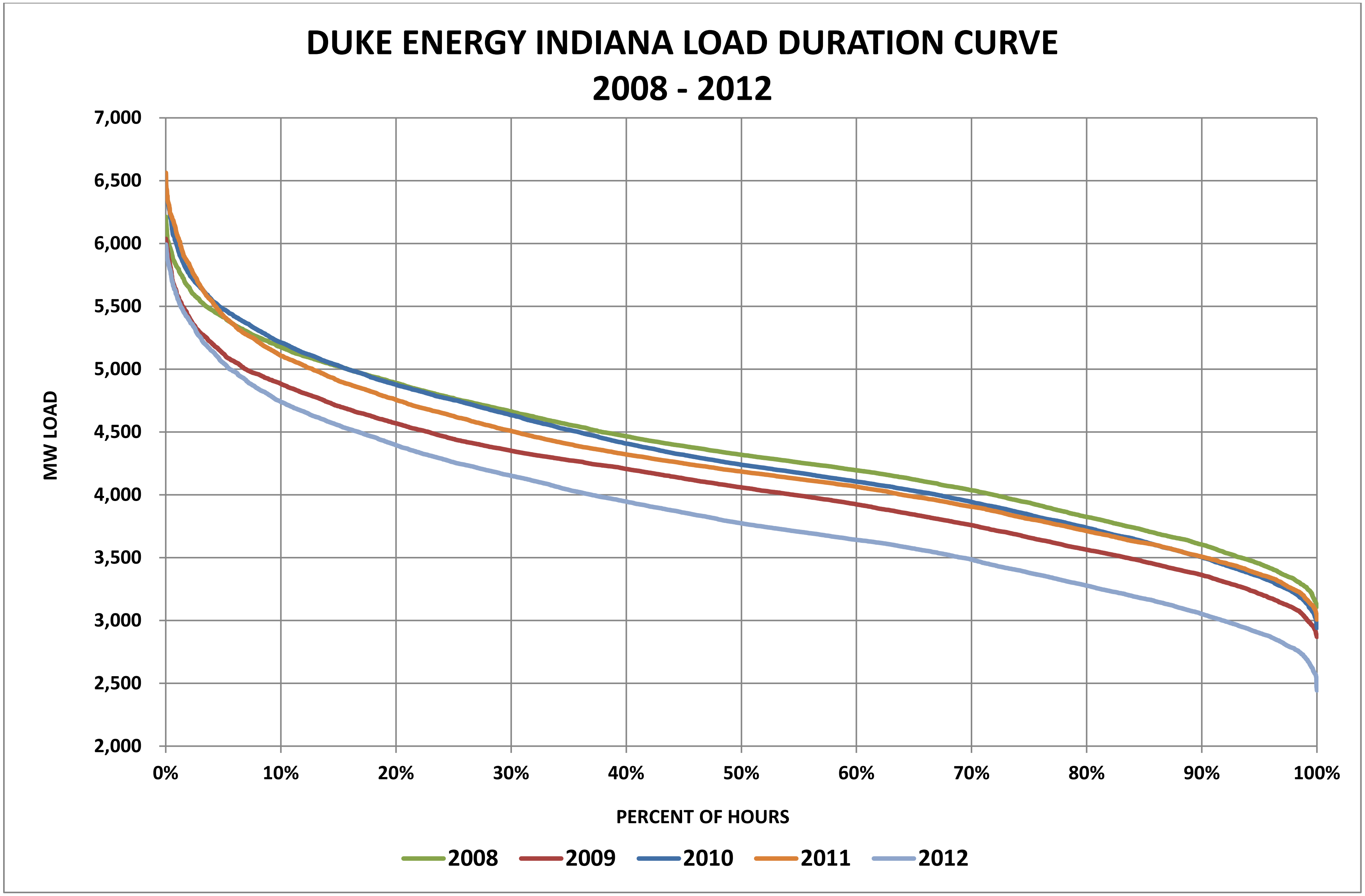
	Actual	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
2001-02	5,098											
2002-03	5,475	5,281										
2003-04	5,568	5,386	5,616									
2004-05	5,701	5,461	5,718	5,775								
2005-06	5,617	5,437	5,814	5,796	5,885							
2006-07	5,762	5,254	5,649	5,870	5,944	5,691						
2007-08	5,996	5,290	5,727	5,755	5,530	5,330	6,043					
2008-09	5,920	5,332	5,770	5,824	5,584	5,375	6,096	6,153				
2009-10	5,602	5,409	5,832	5,845	5,645	5,418	6,157	6,199	6,154			
2010-11	5,878	5,452	5,888	5,907	5,709	5,472	6,226	6,262	6,202	5,920		
2011-12	5,603	5,508	5,944	5,990	5,773	5,535	6,296	6,307	6,243	5,971	5,988	
2012-13	5,763	5,561	6,035	5,986	5,835	5,597	6,361	6,353	6,216	6,039	5,993	6,131

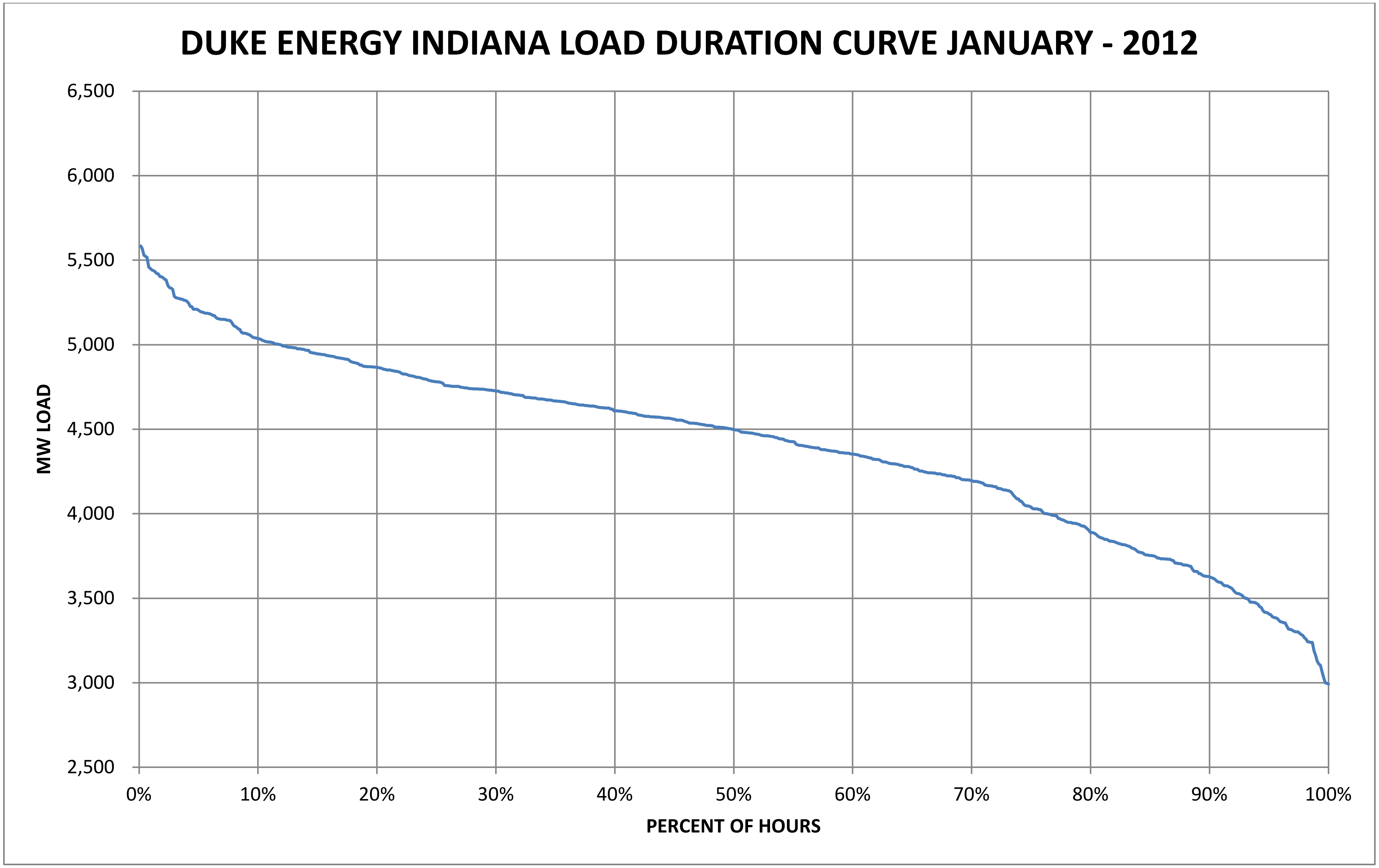
Forecasts reflect weather normal peaks before the impact of demand response
History reflects actual peaks after the impact of demand response

6. Load Shapes

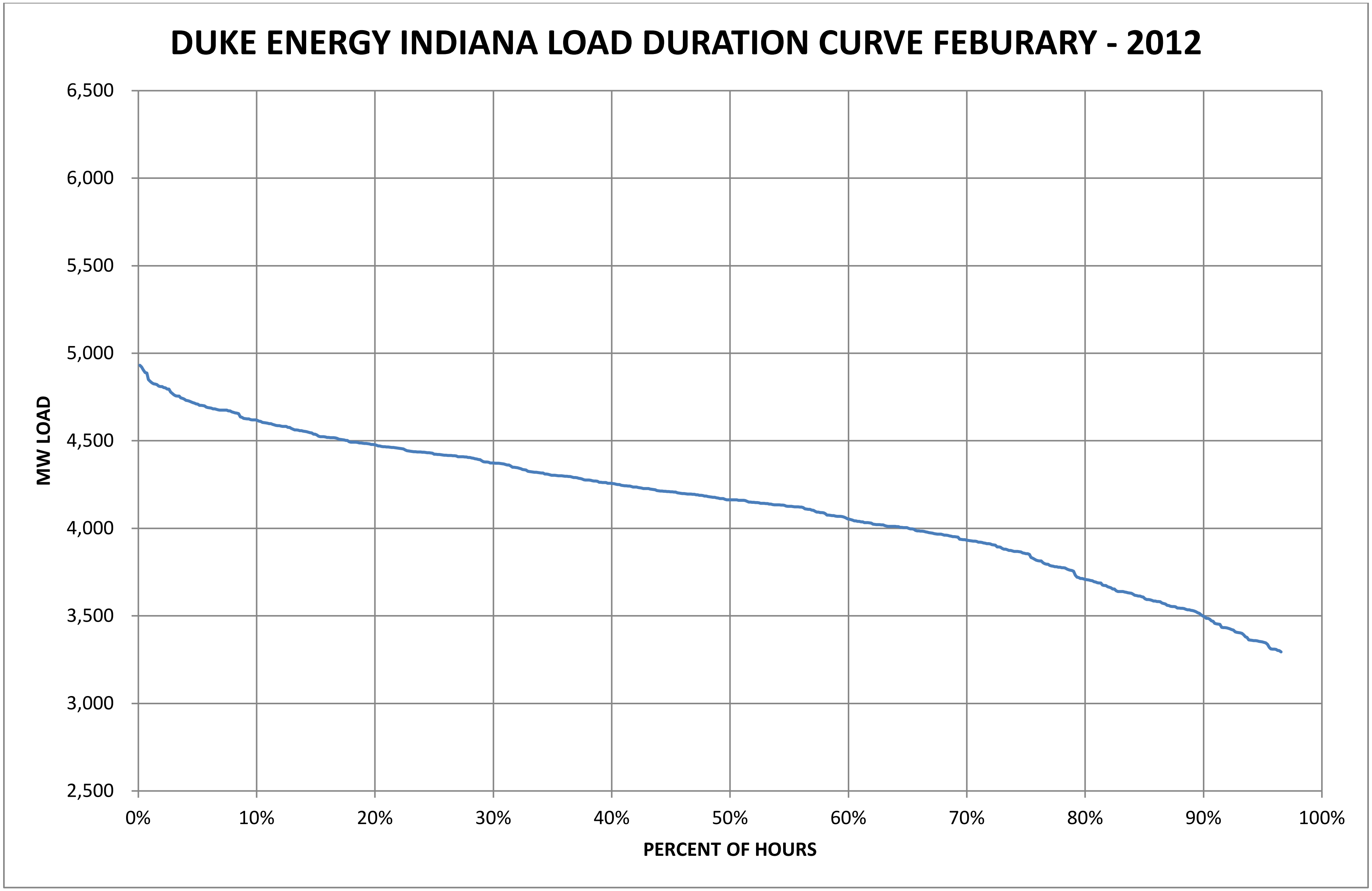
Graphical representations of the annual load duration curves annually for 2008-2012 and monthly for 2012 follow.

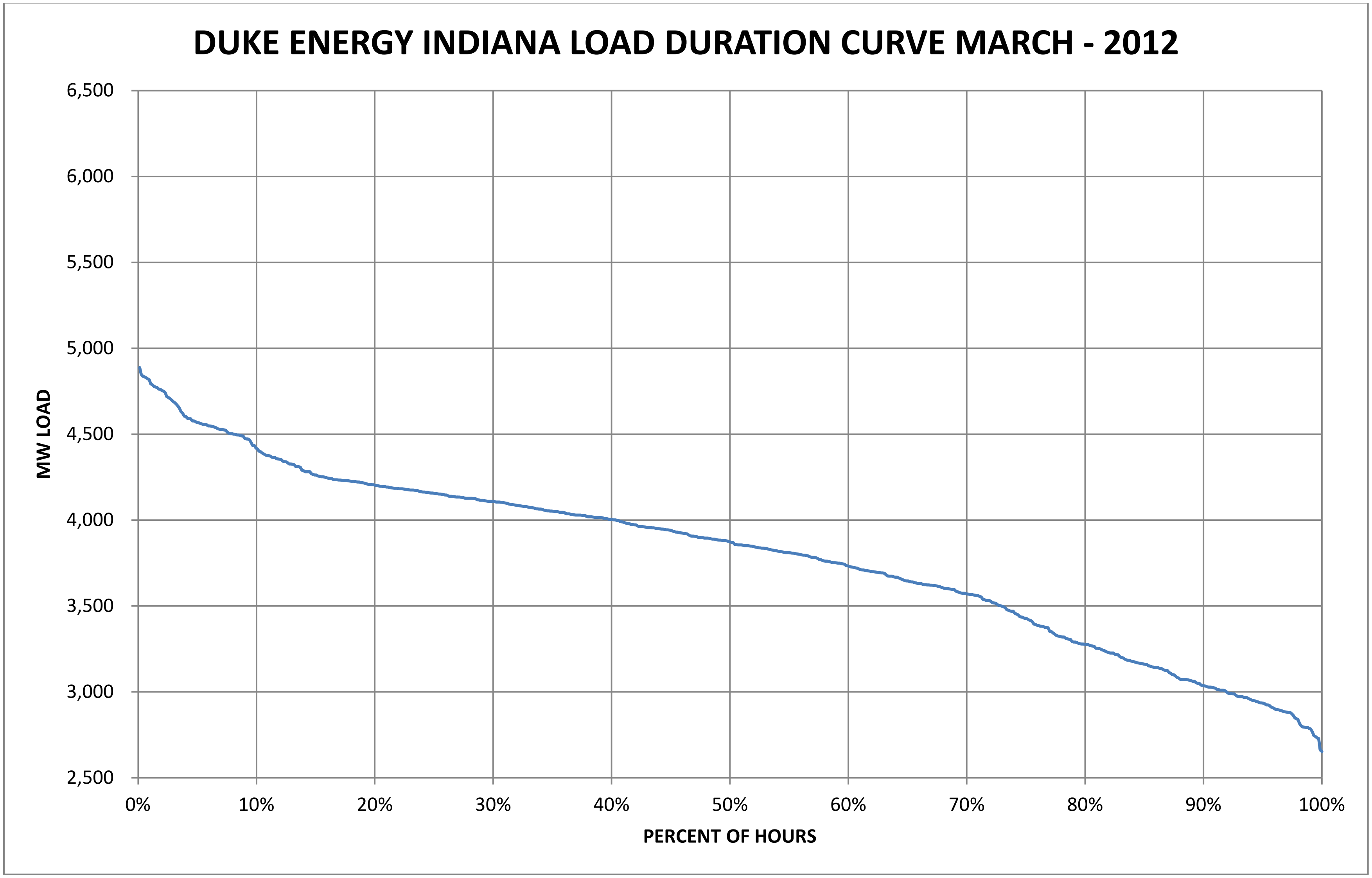
Summer and winter peak day load shapes for 2008-2012 follow. Typical summer and winter weekday and weekend shapes are also attached. For the forecast period, no significant trends or changes from the historic load shapes are expected.

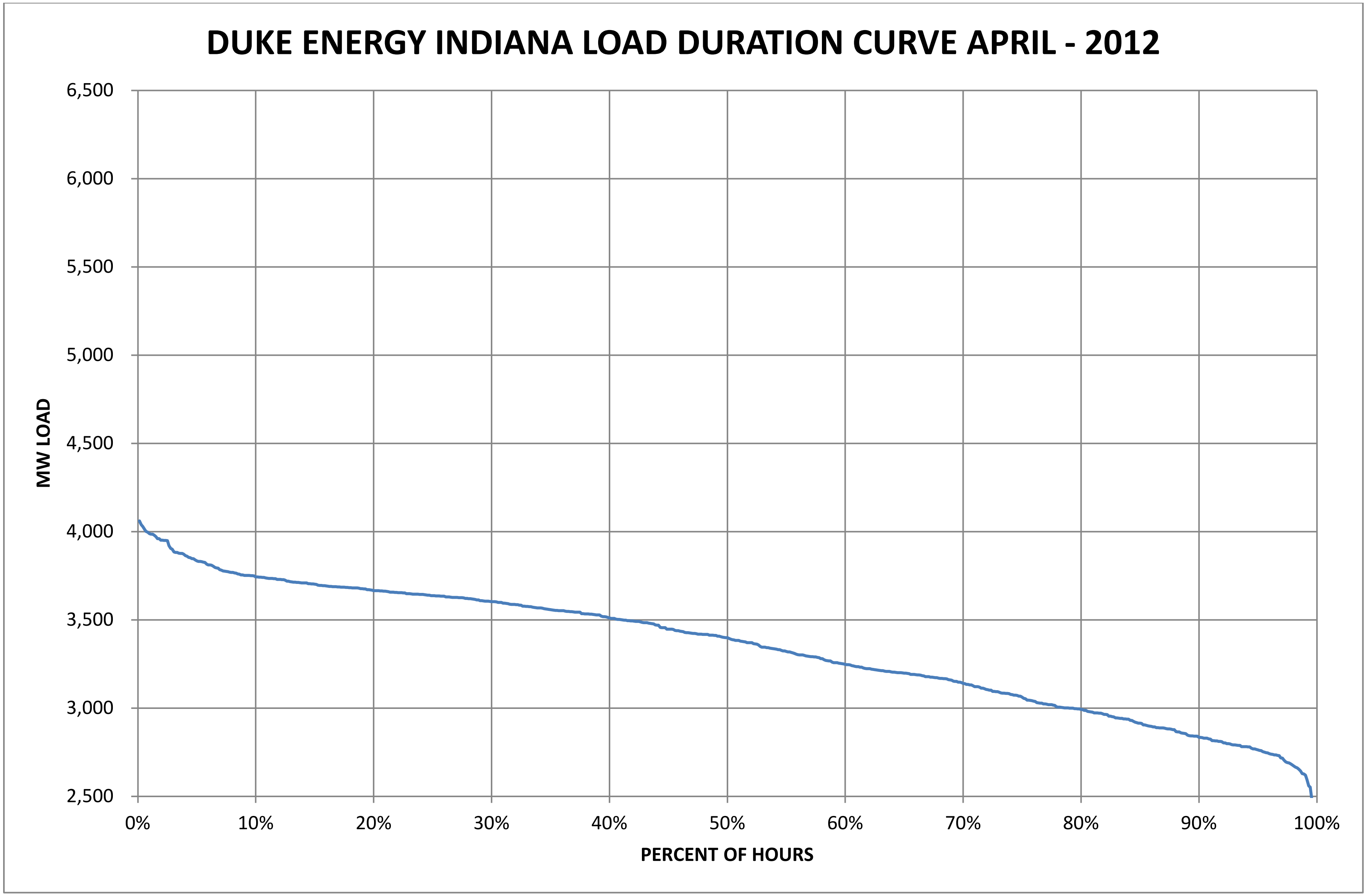

DUKE ENERGY INDIANA LOAD DURATION CURVE
2008 - 2012
7,000
6,500
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
2,000
MW LOAD
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
PERCENT OF HOURS
2008
2009
2010
2011
2012

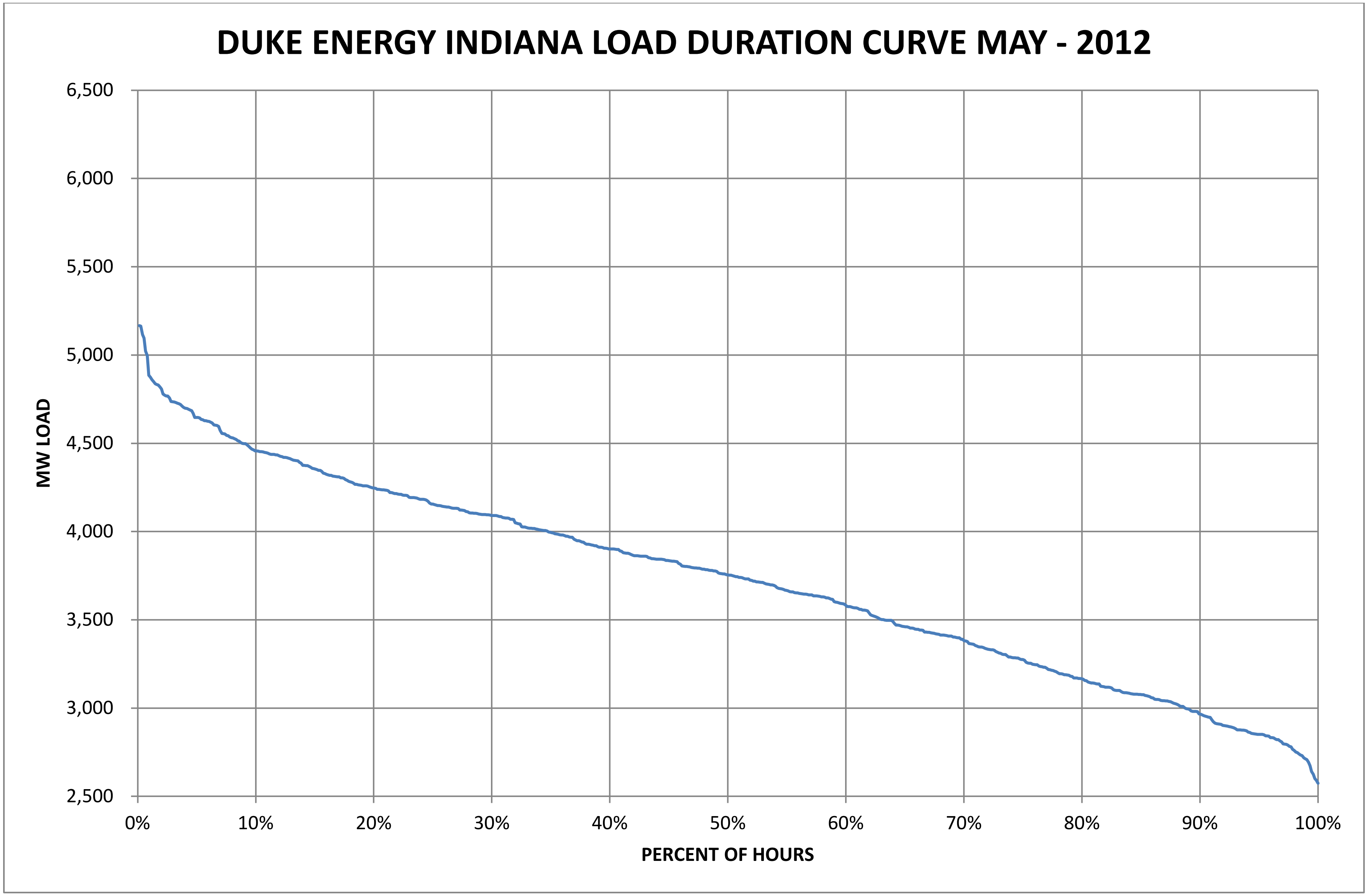


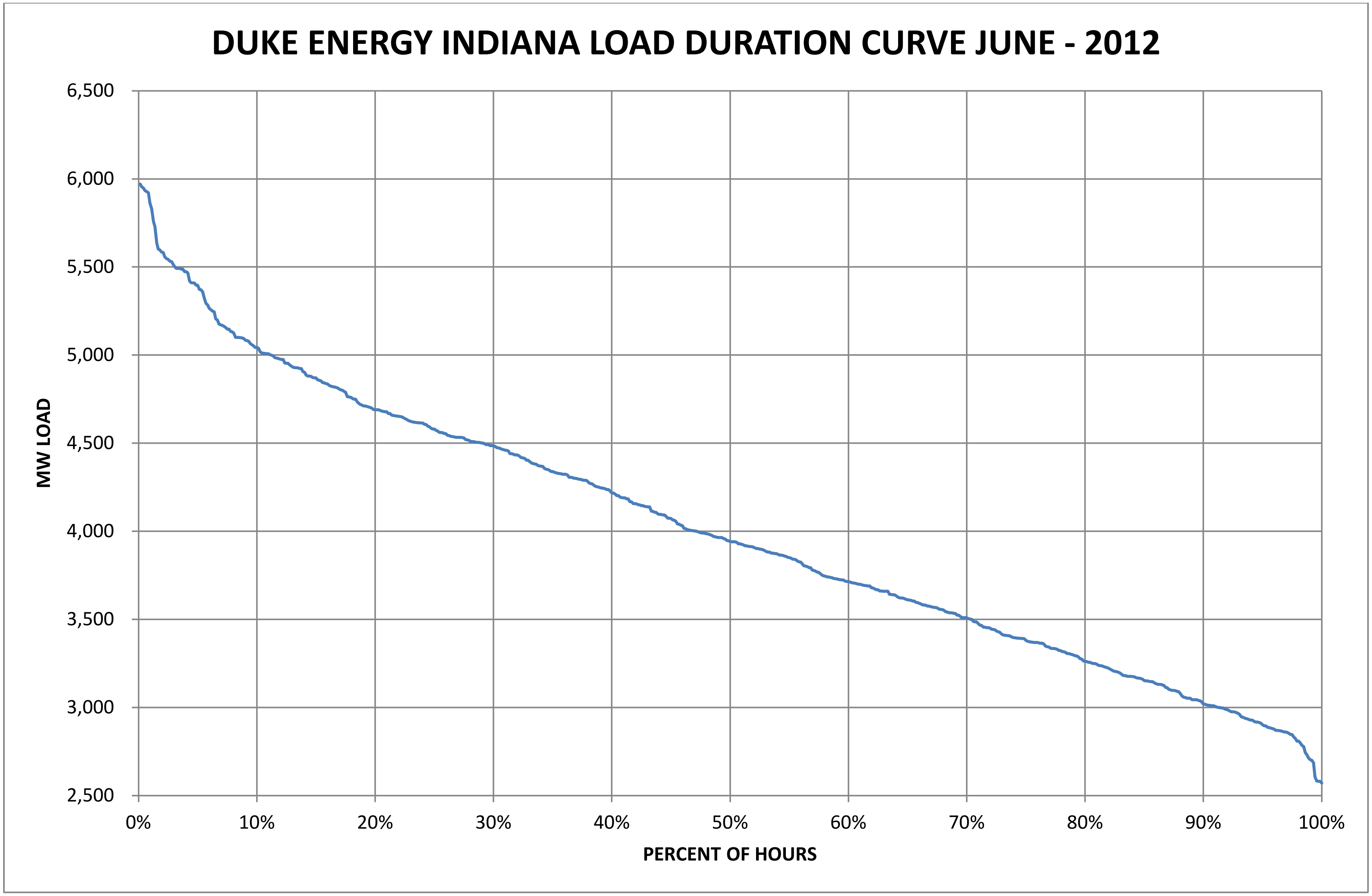
DUKE ENERGY INDIANA LOAD DURATION CURVE JANUARY - 2012
6,500
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
MW LOAD
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
PERCENT OF HOURS

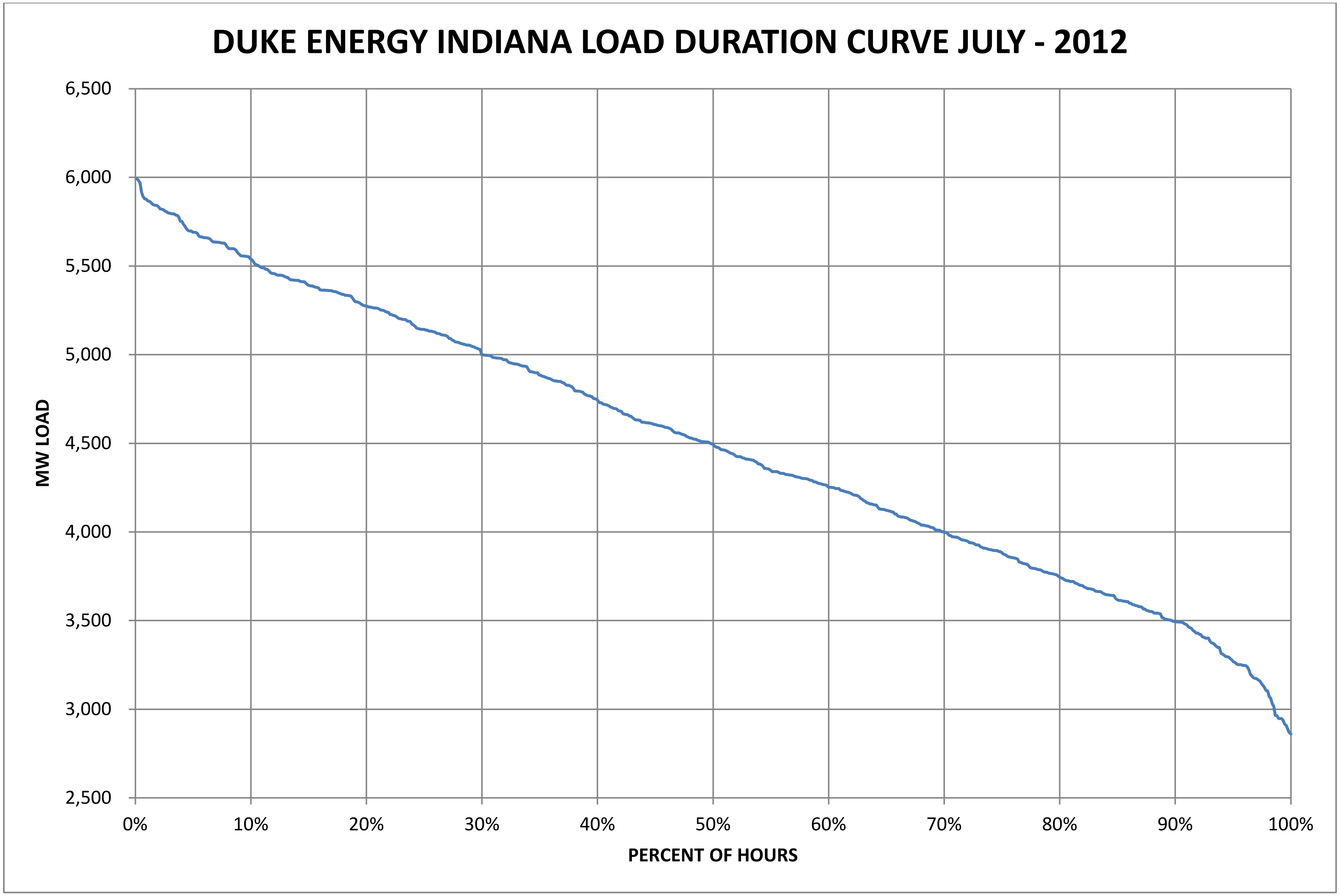

DUKE ENERGY INDIANA LOAD DURATION CURVE FEBURARY - 2012
MW LOAD
6,500
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
PERCENT OF HOURS

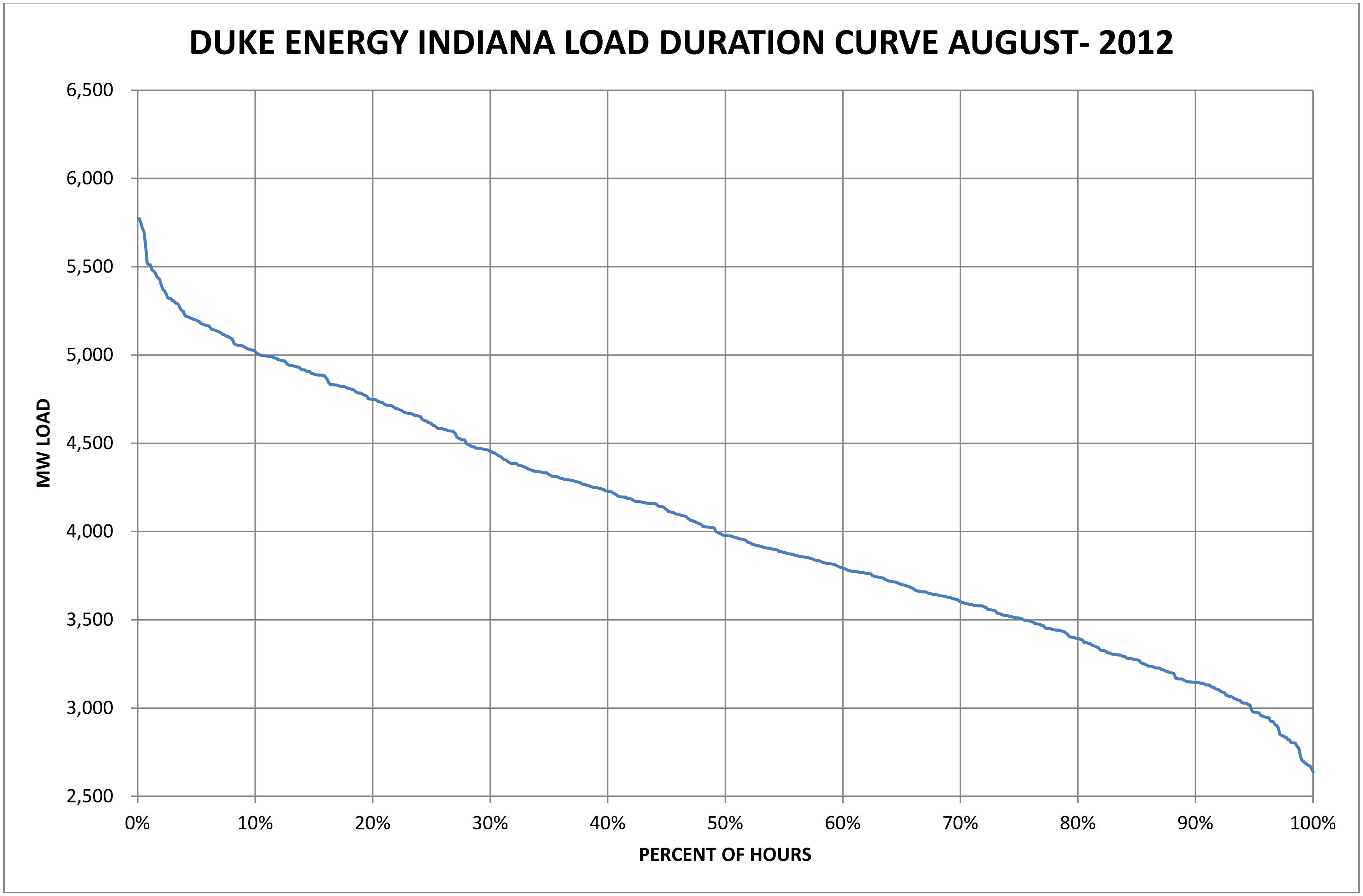

DUKE ENERGY INDIANA LOAD DURATION CURVE MARCH - 2012
MW LOAD
6,500
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
PERCENT OF HOURS

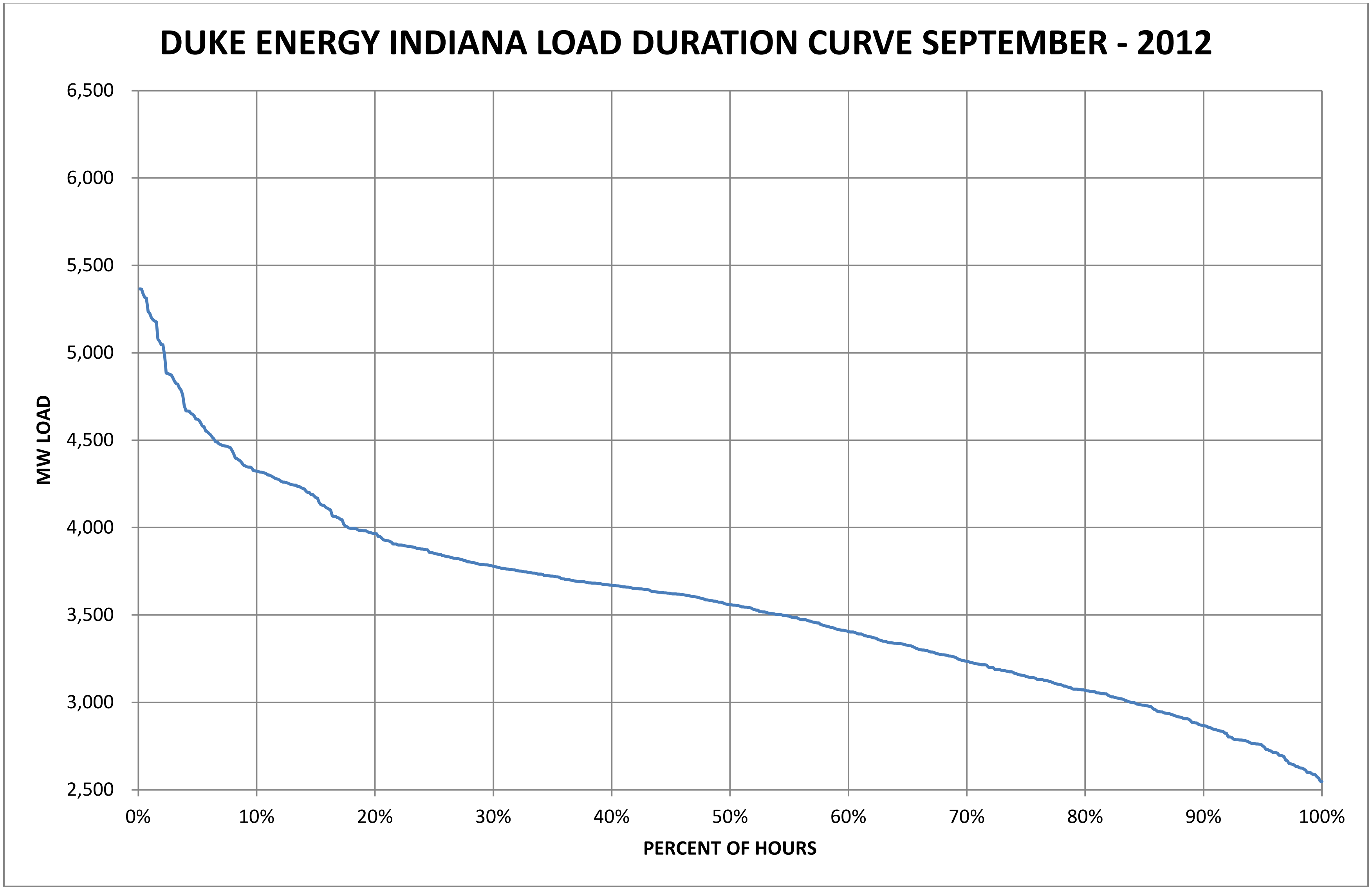

DUKE ENERGY INDIANA LOAD DURATION CURVE APRIL - 2012
6,500
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
MW LOAD
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
PERCENT OF HOURS

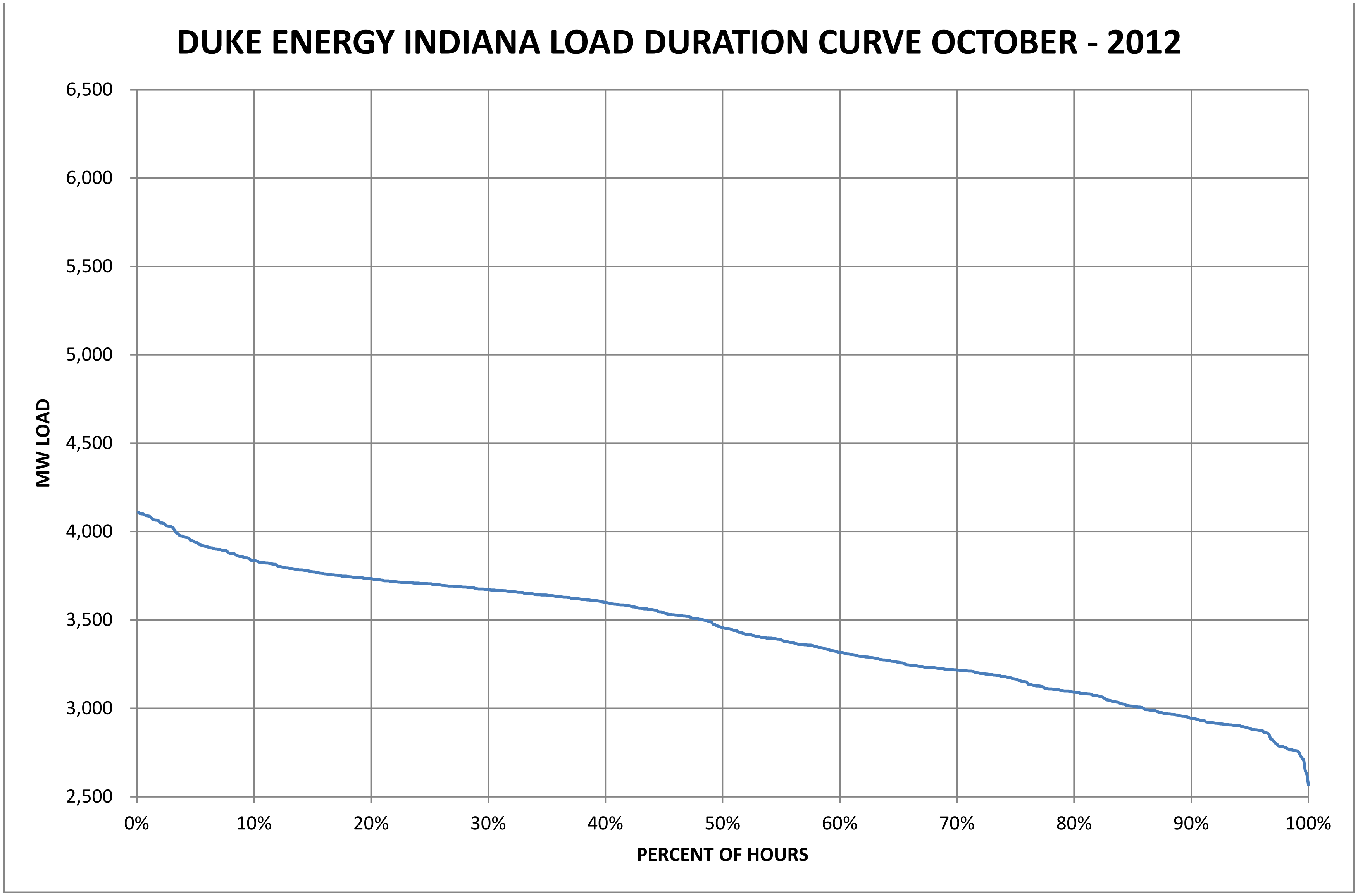

DUKE ENERGY INDIANA LOAD DURATION CURVE MAY - 2012
MW LOAD
6,500
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
PERCENT OF HOURS

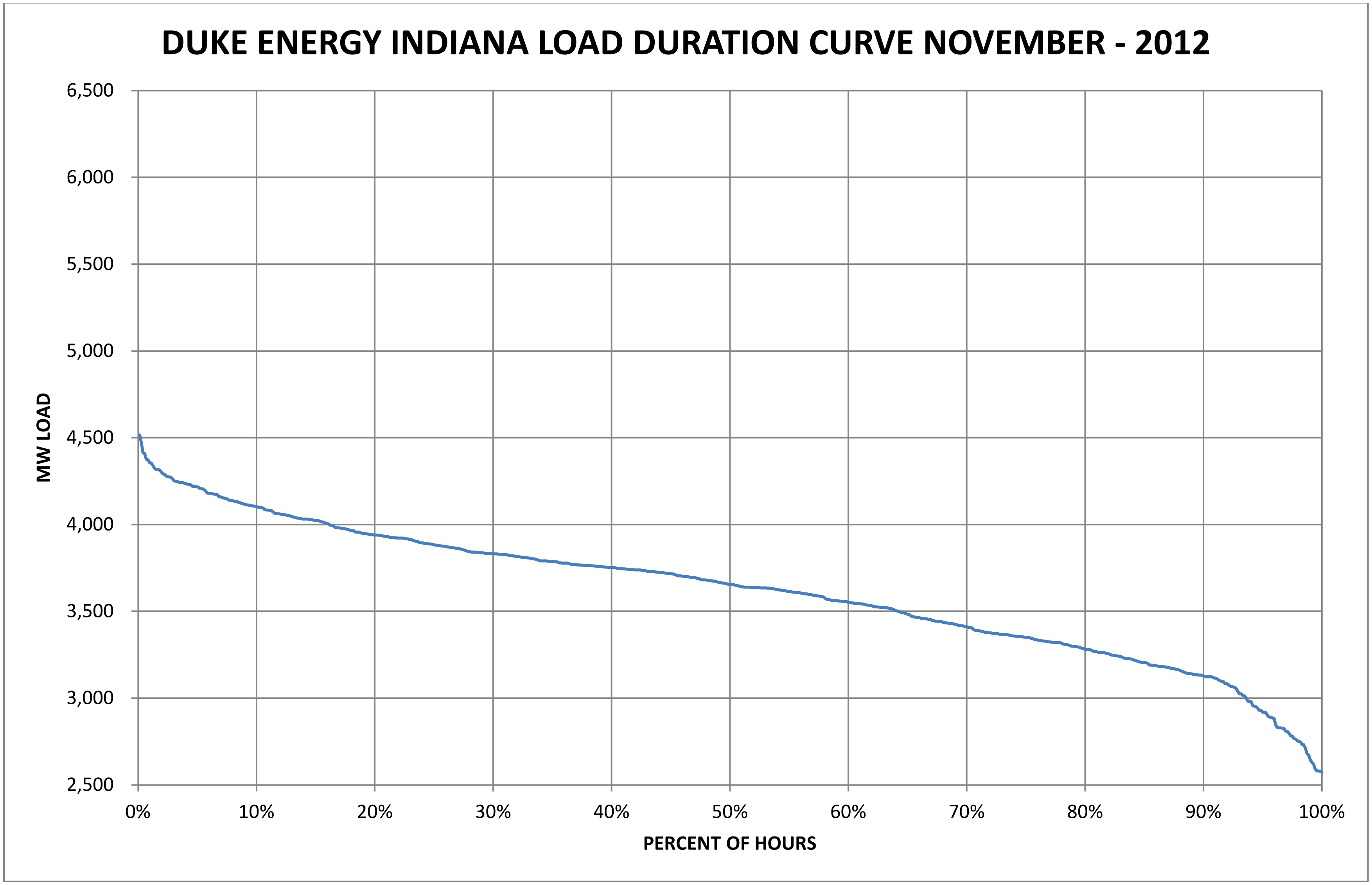

DUKE ENERGY INDIANA LOAD DURATION CURVE JUNE - 2012
MW LOAD
6,500
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
PERCENT OF HOURS

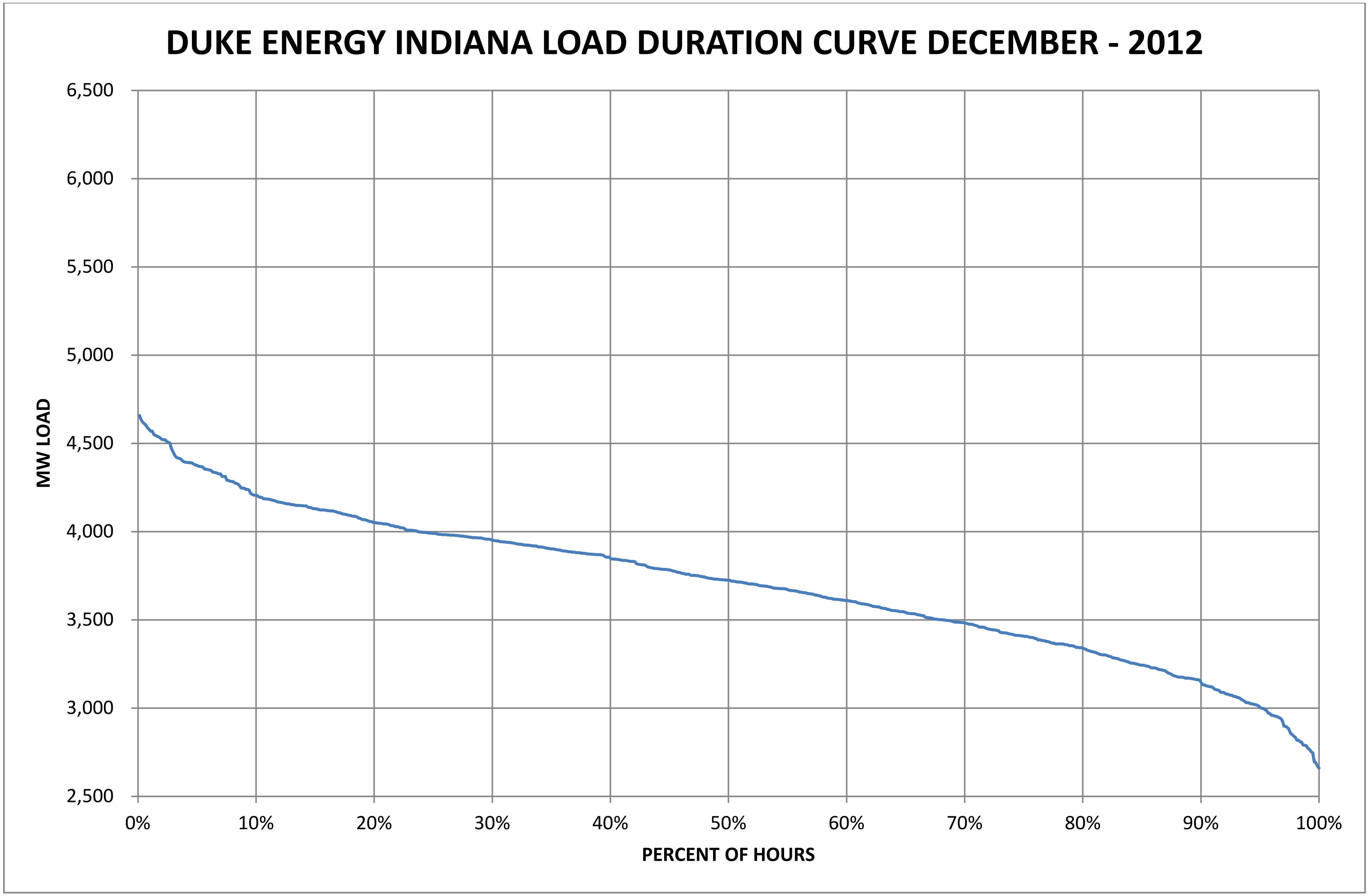

DUKE ENERGY INDIANA LOAD DURATION CURVE JULY - 2012
MW LOAD
6,500
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
PERCENT OF HOURS

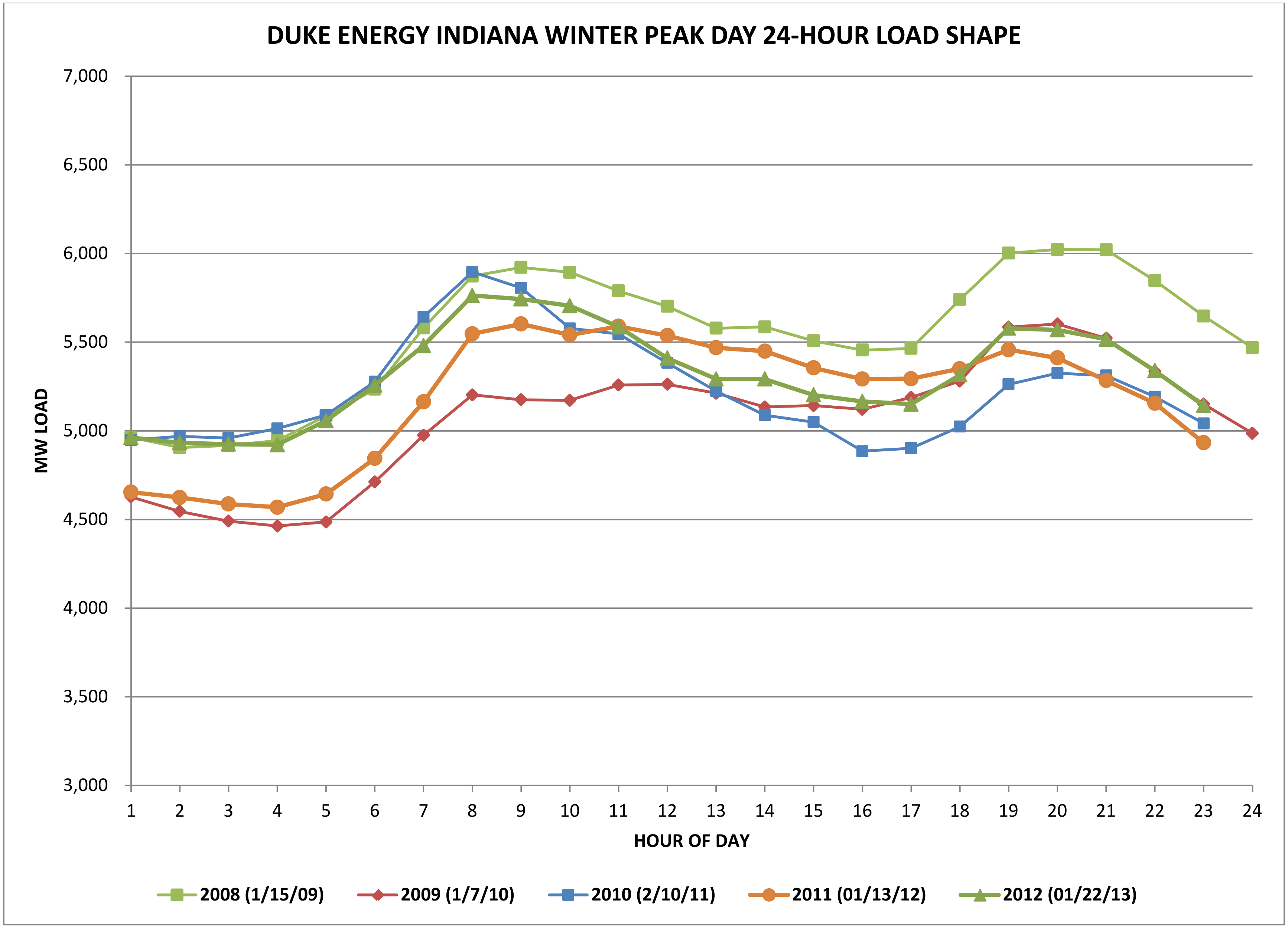

DUKE ENERGY INDIANA LOAD DURATION CURVE AUGUST- 2012
MW LOAD
6,500
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
PERCENT OF HOURS


DUKE ENERGY INDIANA LOAD DURATION CURVE SEPTEMBER - 2012
MW LOAD
6,500
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
PERCENT OF HOURS


DUKE ENERGY INDIANA LOAD DURATION CURVE OCTOBER - 2012
MW LOAD
6,500
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
PERCENT OF HOURS

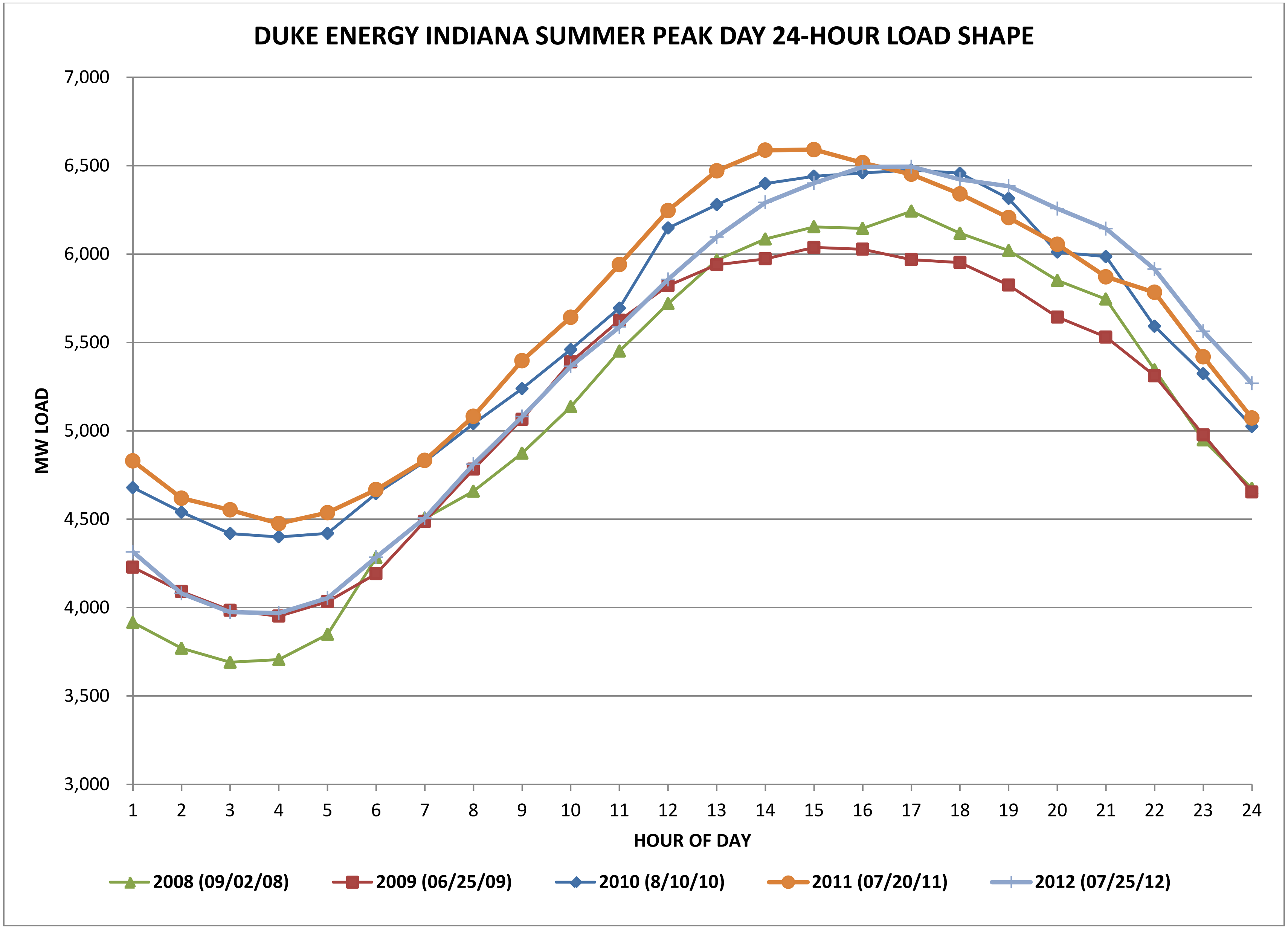

DUKE ENERGY INDIANA LOAD DURATION CURVE NOVEMBER - 2012
MW LOAD
6,500
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
PERCENT OF HOURS

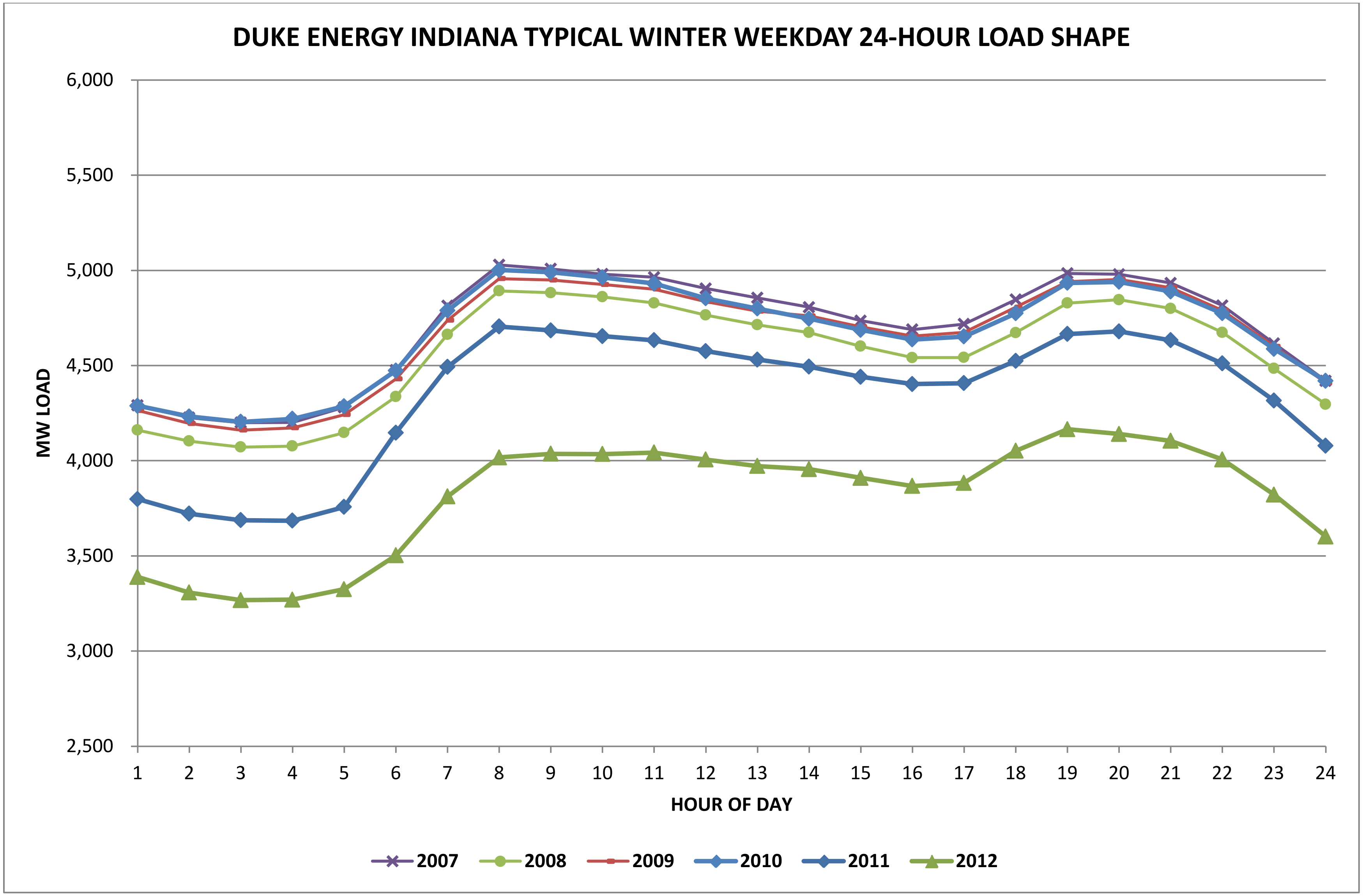

DUKE ENERGY INDIANA LOAD DURATION CURVE DECEMBER - 2012
MW LOAD
6,500
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
PERCENT OF HOURS

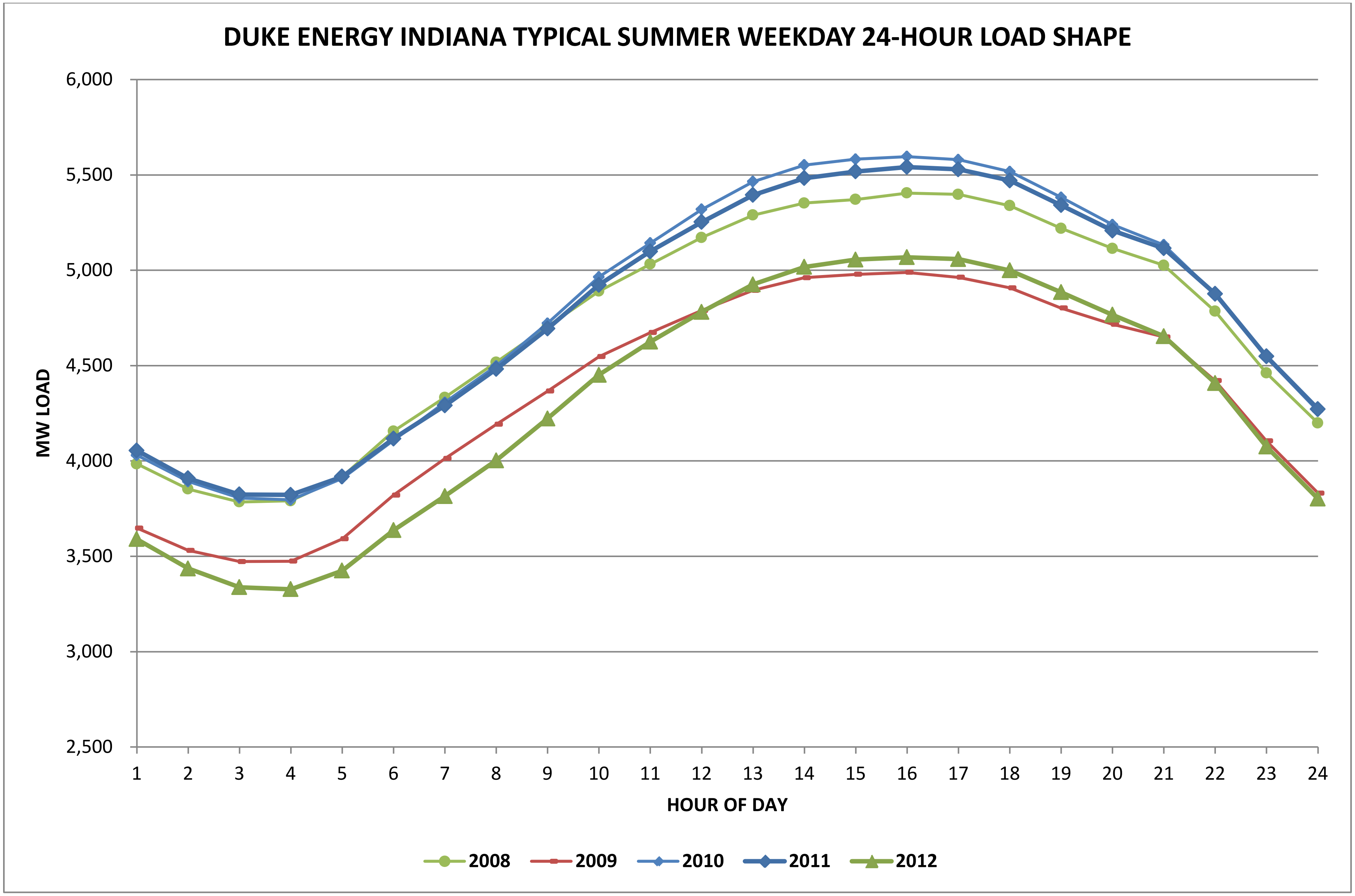


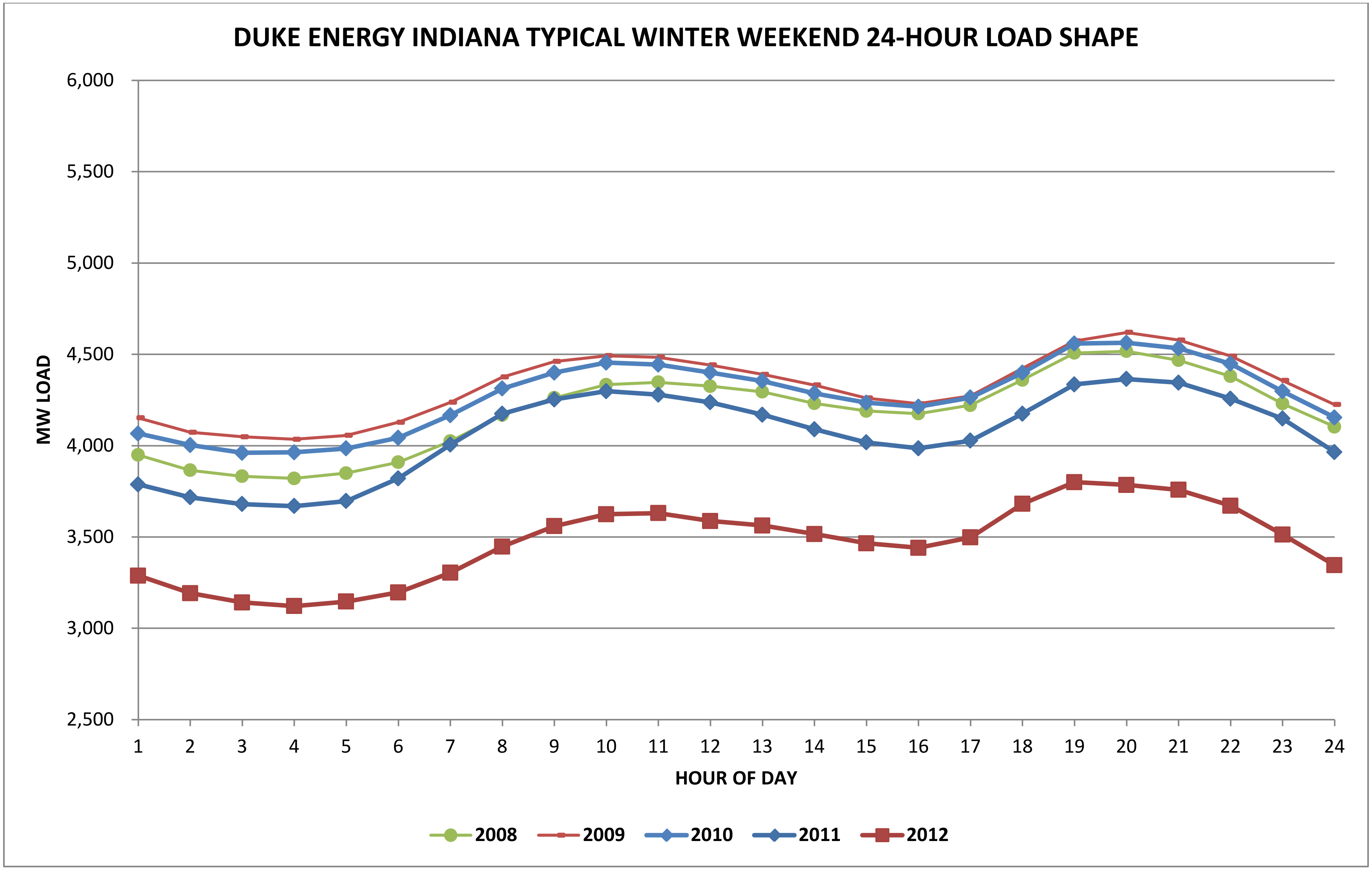
DUKE ENERGY INDIANA WINTER PEAK DAY 24-HOUR LOAD SHAPE
7,000
6,500
6,000
5,500
5,000
4,500
4,000
3,500
3,000
MW LOAD
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
HOUR OF DAY
2008 (1/15/09)
2009 (1/7/10)
2010 (2/10/11)
2011 (01/13/12)
2012 (01/22/13)

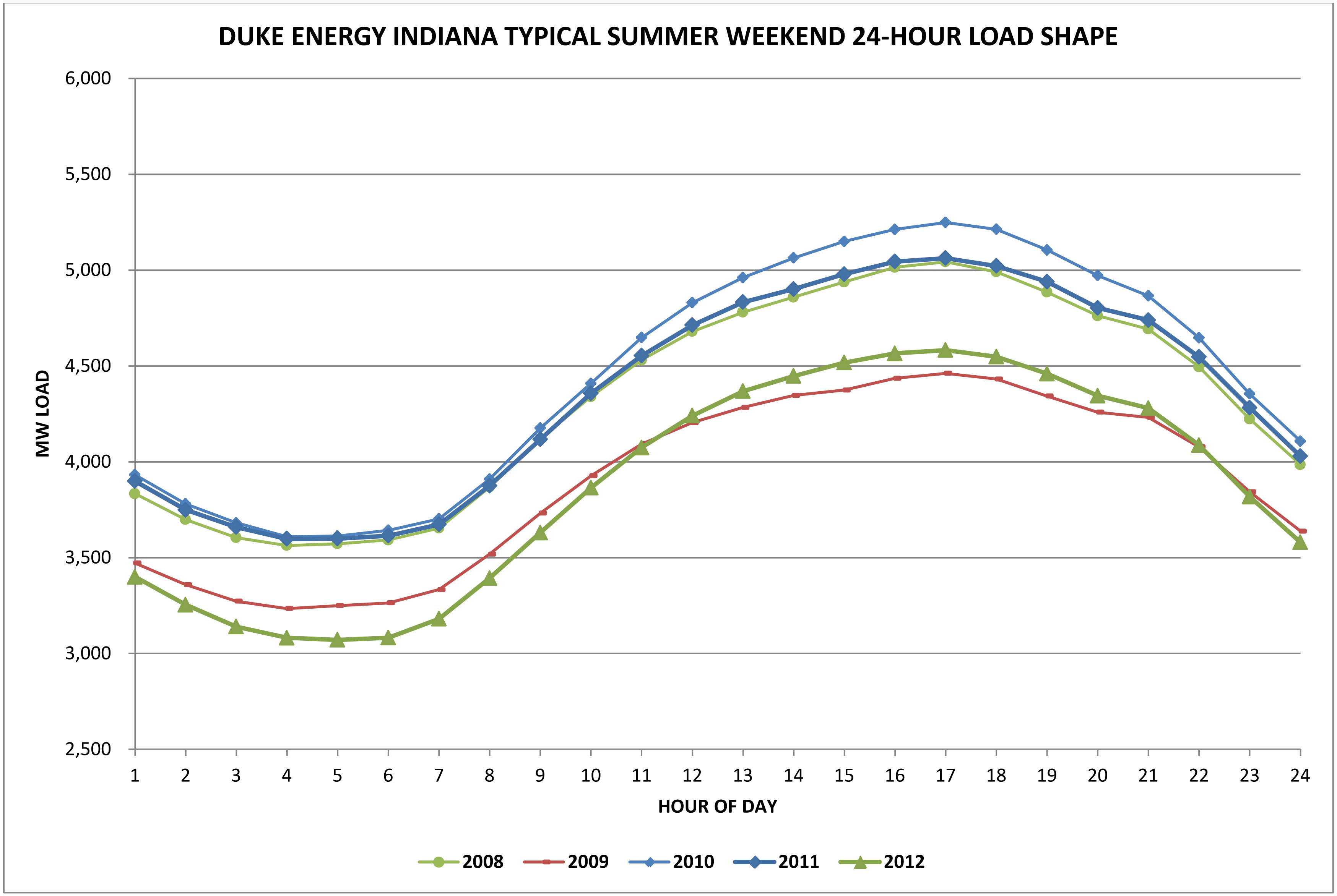
205


DUKE ENERGY INDIANA SUMMER PEAK DAY 24-HOUR LOAD SHAPE
MW LOAD
7,000
6,500
6,000
5,500
5,000
4,500
4,000
3,500
3,000
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
HOUR OF DAY
2008 (09/02/08)
2009 (06/25/09)
2010 (8/10/10)
2011 (07/20/11)
2012 (07/25/12)


DUKE ENERGY INDIANA TYPICAL WINTER WEEKDAY 24-HOUR LOAD SHAPE
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
MW LOAD
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
HOUR OF DAY
2007
2008
2009
2010
2011
2012


DUKE ENERGY INDIANA TYPICAL SUMMER WEEKDAY 24-HOUR LOAD SHAPE
MW LOAD
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
HOUR OF DAY
2008
2009
2010
2011
2012


DUKE ENERGY INDIANA TYPICAL WINTER WEEKEND 24-HOUR LOAD SHAPE
MW LOAD
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
HOUR OF DAY
2008
2009
2010
2011
2012



DUKE ENERGY INDIANA TYPICAL SUMMER WEEKEND 24-HOUR LOAD SHAPE
MW LOAD
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
HOUR OF DAY
2008
2009
2010
2011
2012

7. Disaggregated Load Shapes

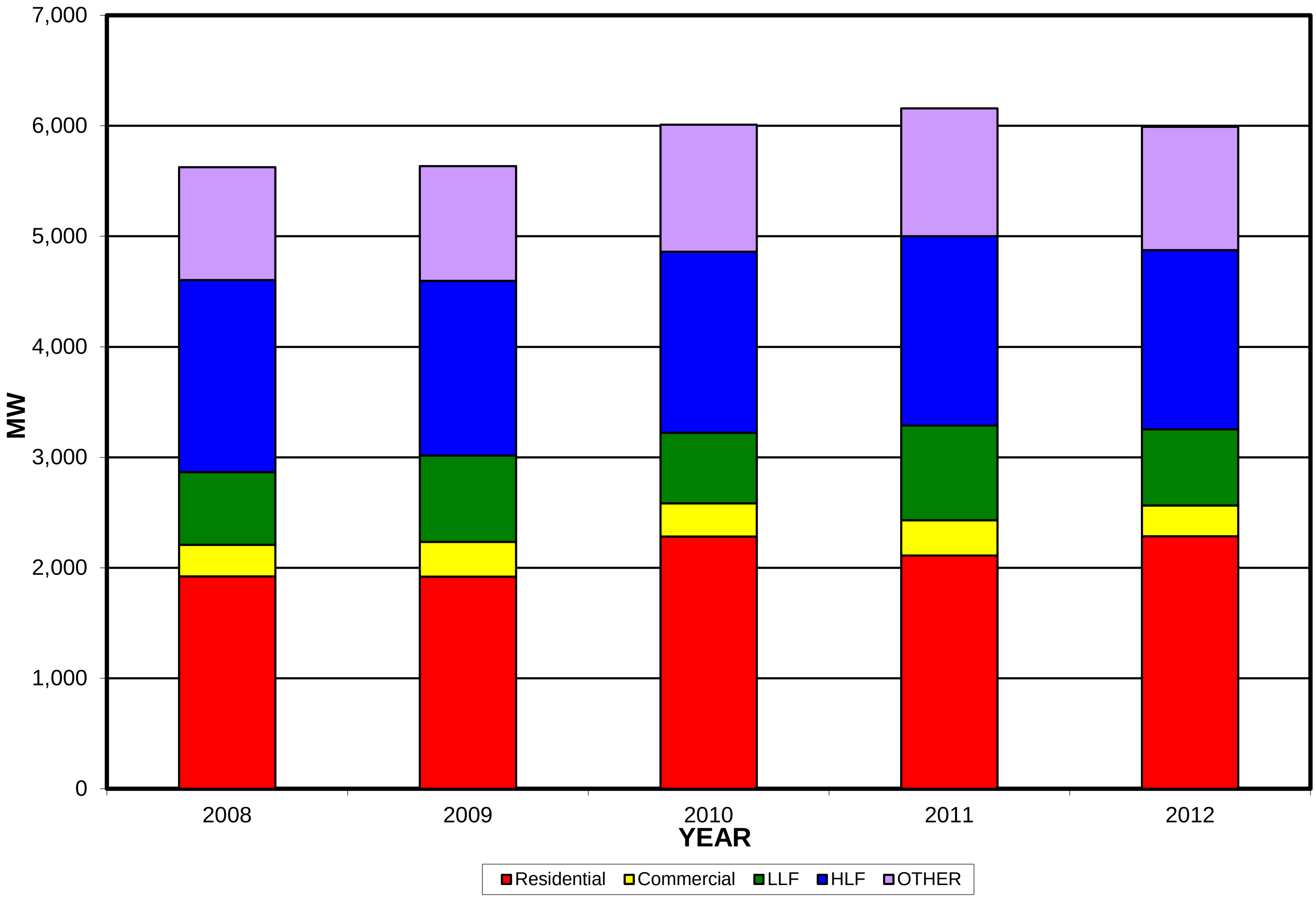
The graphs showing Rate Group Contribution to Duke Energy Indiana System Peaks for the years 2008 through 2012 are attached.

Differences in peak from those reported elsewhere arise from:

- A different method for determining the hour of peak,
- Differences in how wholesale contracts including backstands are counted, and
- Demand Response.

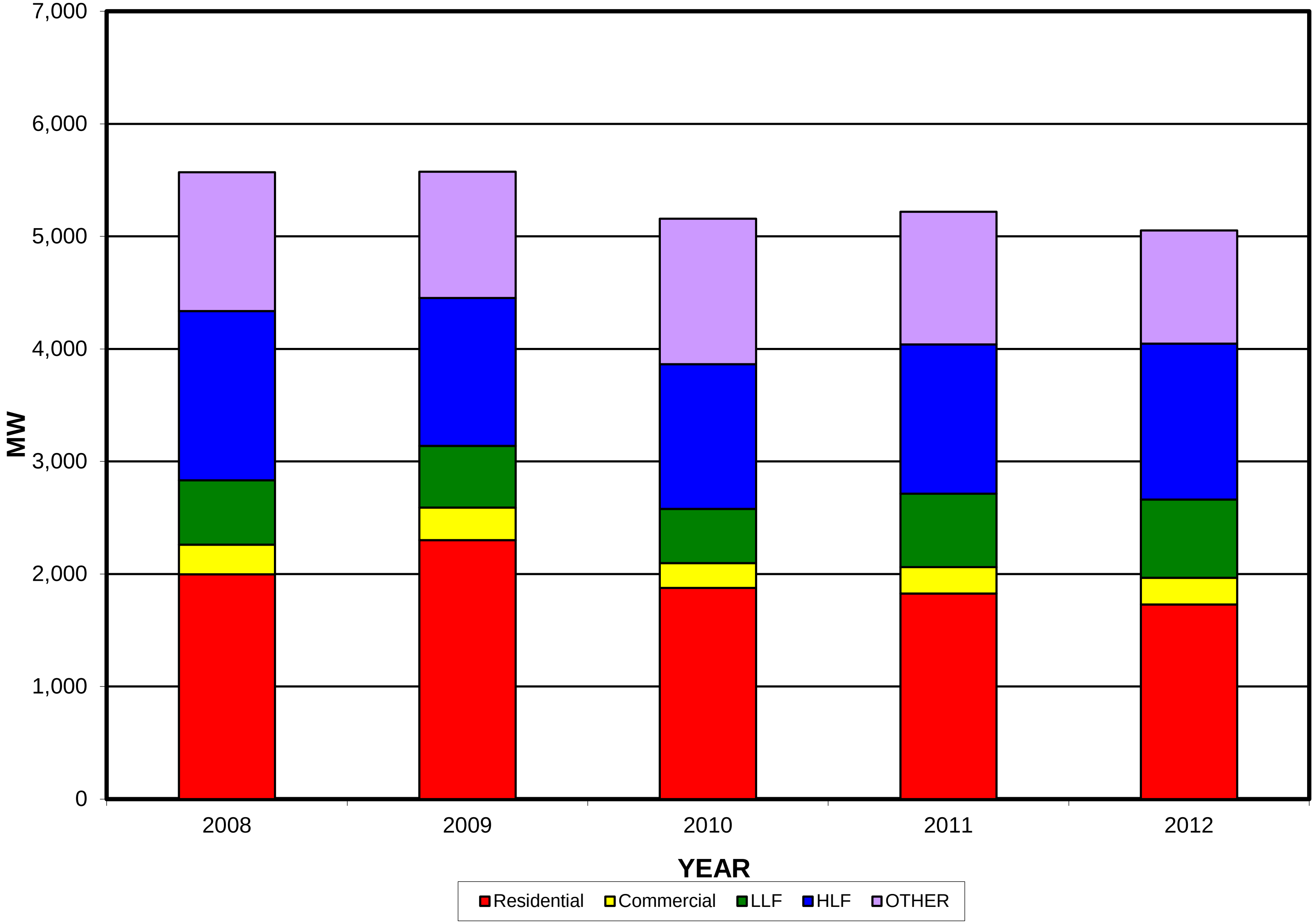
RATE GROUP CONTRIBUTION TO DUKE ENERGY INDIANA SUMMER SYSTEM PEAK

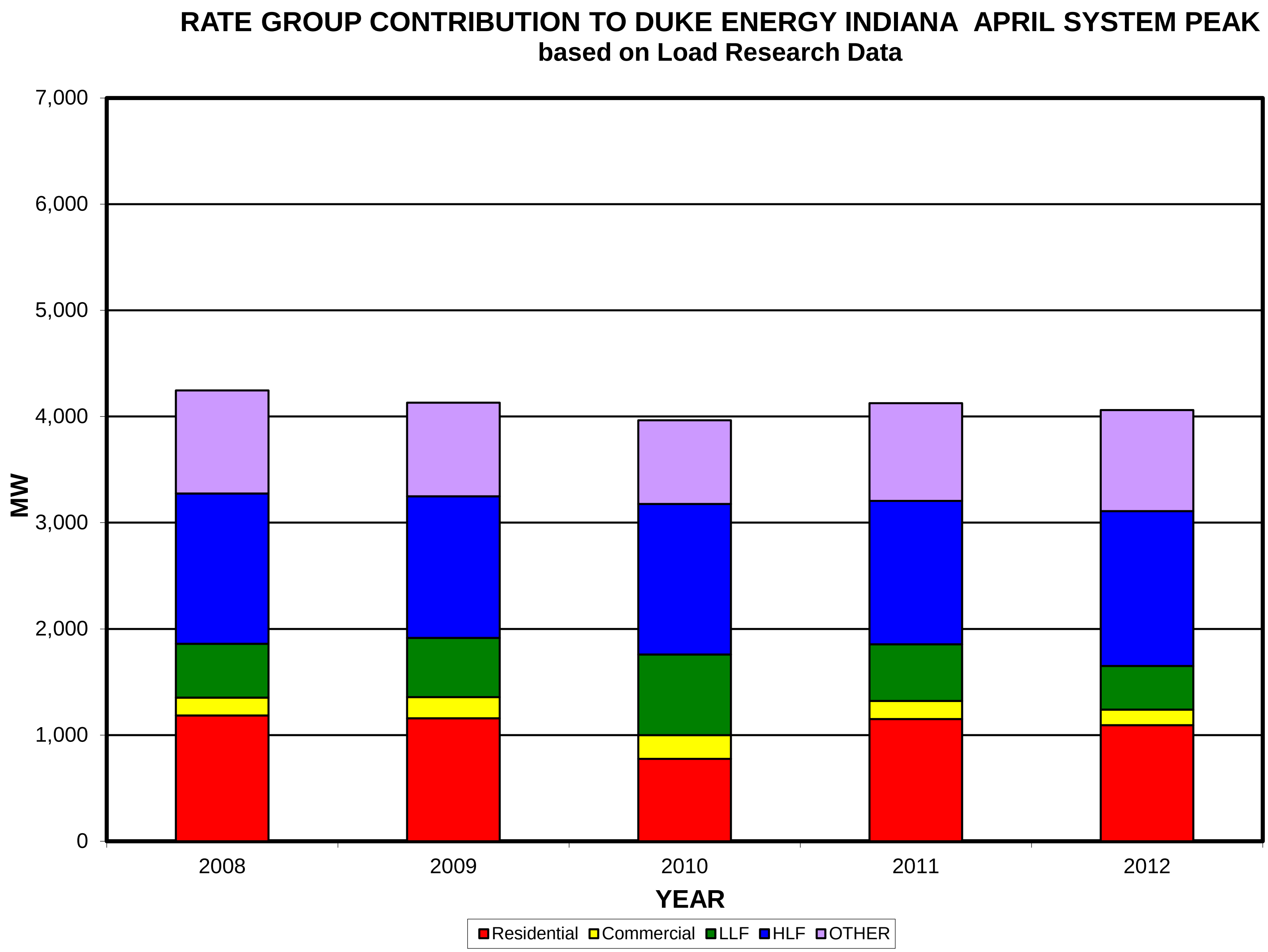
based on Load Research Data

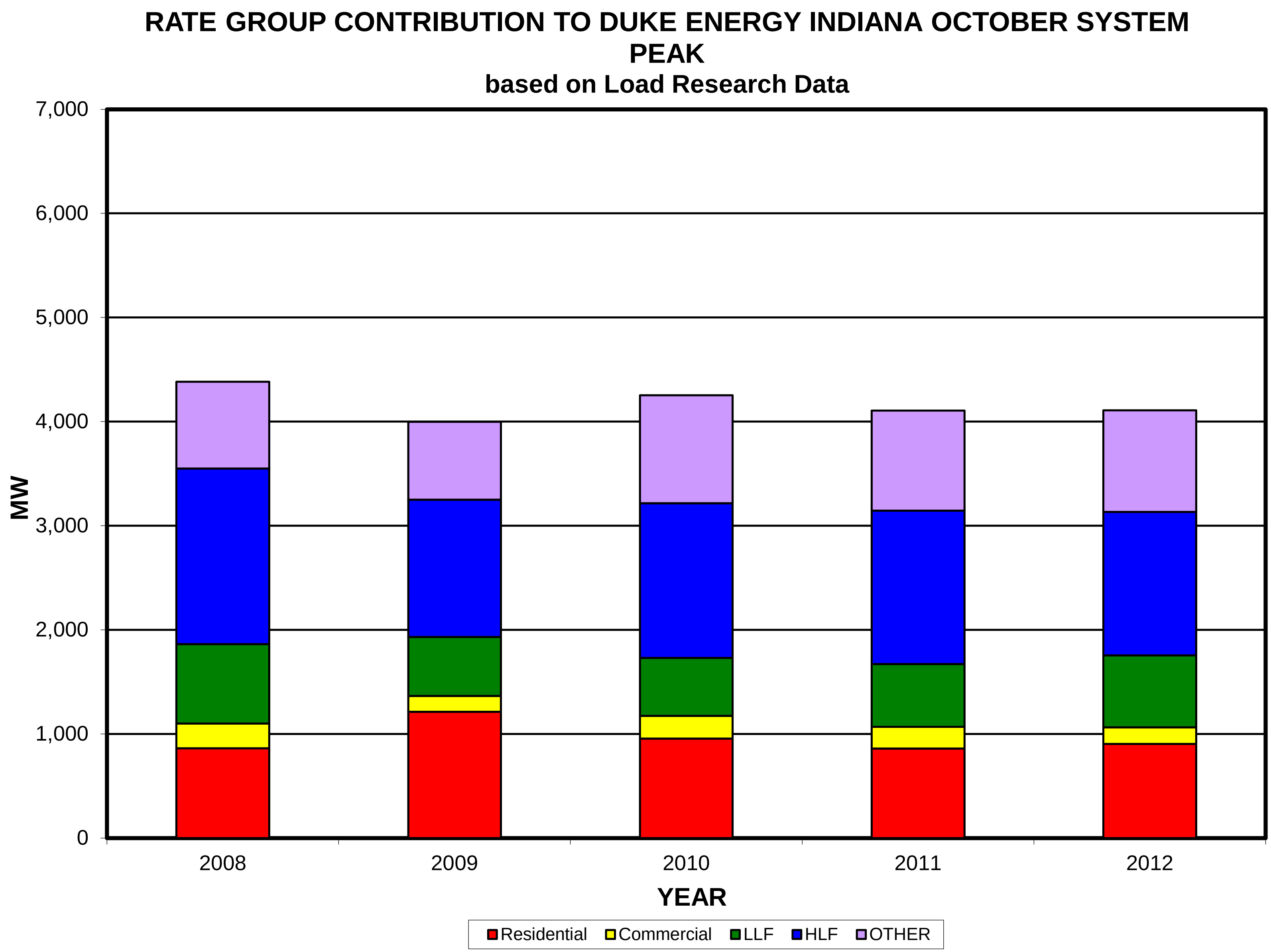


RATE GROUP CONTRIBUTION TO DUKE ENERGY INDIANA JANUARY SYSTEM PEAK

based on Load Research Data




RATE GROUP CONTRIBUTION TO DUKE ENERGY INDIANA APRIL SYSTEM PEAK
based on Load Research Data
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
MW
2008
2009
2010
2011
2012
YEAR
Residential
Commercial
LLF
HLF
OTHER


RATE GROUP CONTRIBUTION TO DUKE ENERGY INDIANA OCTOBER SYSTEM PEAK
based on Load Research Data
MW
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
2008
2009
2010
2011
2012
YEAR
Residential
Commercial
LLF
HLF
OTHER

8. Weather-Normalized Energy and Demand Levels

DUKE ENERGY INDIANA
ACTUAL AND WEATHER NORMALIZED PEAKS (MW)

SUMMER			WINTER		
YEAR	ACTUAL	WEATHER NORMALIZED		ACTUAL	WEATHER NORMALIZED
2001	6,101	6,224	2001-02	5,098	5,247
2002	6,250	6,397	2002-03	5,595	5,488
2003	6,269	6,564	2003-04	5,568	5,597
2004	6,136	6,409	2004-05	5,701	5,873
2005	6,766	6,692	2005-06	5,617	5,775
2006	6,702	6,739	2006-07	5,933	6,023
2007	6,866	6,804	2007-08	5,996	6,195
2008	6,243	6,493	2008-09	6,023	5,954
2009	6,037	6,194	2009-10	5,602	5,985
2010	6,476	6,491	2010-11	5,878	6,067
2011	6,749	6,490	2011-12	5,475	5,152
2012	6,494	6,510	2012-13	5,769	5,273

Note: Actual peak loads have been increased to include past impacts from demand response programs.

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Appendix C:
Energy Efficiency

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1. Avoided Cost for EE Screening

The avoided costs used in screening the Core Plus EE programs were based on information in the Core Plus Program filing (Cause No. 43955) made with the Commission. The Company considers this information to be a trade secret and confidential and competitive information. It will be made available to appropriate parties for viewing at Duke Energy Indiana offices during normal business hours upon execution of an appropriate confidentiality agreement or protective order. Please contact Beth Herriman at (317) 838-1254 for more information.

2. Duke Energy Indiana EE Program Data

The EE Core Plus Program Data is voluminous in nature. This data will be made available to appropriate parties for viewing at Duke Energy Indiana offices during normal business hours. Please contact Beth Herriman at (317) 838-1254 for more information.

The table below provides projections of participation, Gross MWh savings and program expenditures for the Core Plus Programs for 2014-16. Please note that a filing requesting approval of a one year extension of the Core Plus programs for 2014 has been submitted and a new filing for Core Plus programs to be offered in 2015-17 will be submitted for approval early in 2014. The projections listed below for 2015 and 2016 are subject to change in the upcoming 2015-17 extension filing. Similar information for the Core Programs is available from the Third Party Administrator.

Core Plus Programs	Participants Projected 2014	Participants Projected 2015	Participants Projected 2016	Gross MWH Savings at the Meter Projected 2014	Gross MWH Savings at the Meter Projected 2015	Gross MWH Savings at the Meter Projected 2016	Program Expenditures Projected 2014	Program Expenditures Projected 2015	Program Expenditures Projected 2016
C&I Smart Saver	161,886	262,062	275,174	35,168	54,026	57,892	$6,834,305	$8,389,518	$9,021,672
EMIS	3,242	0	1,380	2,884	0	1,124	$388,620	$78,412	$175,232
Residential Smart Saver	2,600	4,240	4,240	4,286	7,647	7,647	$1,474,721	$2,333,008	$2,169,837
Agency Kit & CFL's	3,000	5,000	2,500	1,904	3,173	1,586	$135,079	$212,995	$123,394
Fridge/Freezer Recycling	3,000	7,000	7,000	4,729	11,104	11,104	$466,231	$1,006,187	$999,691
Tune and Seal	800	7,296	7,296	422	2,381	2,381	$427,256	$2,261,961	$2,030,176
Home Energy Comparision Report	136,958	274,000	274,000	31,969	35,631	0	$1,859,372	$3,560,307	$3,617,398
Property Manager CFL	6,300	3,600	3,600	249	142	142	$168,072	$15,057	$15,085
Total Core Plus Programs By Year	317,786	563,198	575,190	81,611	114,105	81,878	$11,753,656	$17,857,445	$18,152,485

3. Benefit/Cost Test Components and Equations

BENEFIT/COST TEST MATRIX

Benefits:	Participant Test	Utility Test	Ratepayer Impact Test	Total Resource Test	Societal Test
Customer Electric Bill Decrease	X				
Customer Non-electric Bill Decrease	X				
Customer O&M a nd Other Cost Decrease	X			X	X
Customer Income Tax Decrease	X			X	
Customer Investment Decrease	X			X	X
Customer Rebates Received	X				
Utility Revenue Increase			X		
Utility Electric Production Cost Decrease		X	X	X	X
Utility Generation Capacity Credit		X	X	X	X
Utility Transmission Capacity Credit		X	X	X	X
Utility Distribution Capacity Credit		X	X	X	X
Utility Administrative Cost Decrease		X	X	X	X
Utility Cap. Administrative Cost Decrease		X	X	X	X
Non-electric Acquisition Cost Decrease				X	X
Utility Sales Tax Cost Decrease		X	X	X	
Costs:					
Customer Electric Bill Increase	X				
Customer Non-electric Bill Increase	X			X	
Customer O&M and Other Cost Increase	X			X	X
Customer Income Tax Increase	X			X	
Customer Capital Investment Increase	X			X	X
Utility Revenue Decrease			X		
Utility Electric Production Cost Increase		X	X	X	X
Utility Generation Capacity Debit		X	X	X	X
Utility Transmission Capacity Debit		X	X	X	X
Utility Distribution Capacity Debit		X	X	X	X
Utility Rebates Paid		X	X		
Utility Administrative Cost Increase		X	X	X	X
Utility Cap. Administrative Cost Increase		X	X	X	X
Non-electric Acquisition Cost Increase				X	X
Utility Sales Tax Cost Increase		X	X	X	

Benefit/Cost Ratio = Total Benefits/Total Costs

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Appendix D:
Financial Discussion Information

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Section **Page**

1. NO_x and SO_2 Allowance Price Forecasts

The following Figure D-1 contains the NO_x and SO_2 allowance price forecasts used in the development of this IRP. These forecasts are trade secrets and are proprietary to EVA and Duke Energy Indiana. The redacted information will be made available to appropriate parties upon execution of appropriate confidentiality agreements or protective orders. Please contact Beth Herriman at (317) 838-1254 for more information.

Figure D-1

NOx and SO_2 Price Forecasts Nominal $/Ton		
Year	Annual NO_x	Annual SO_2
2013	[redacted]	
2014		
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		

Note: Seasonal NO_x allowance prices are assumed to be the same as the annual value.

2. Annual Avoided Cost

The annual avoided costs for the plan in this IRP are based on the market price forecast. Energy Ventures Analysis considers this forecast to be a trade secret and confidential and competitive information. It will be made available to appropriate parties for viewing at Duke Energy Indiana offices during normal business hours upon execution of an appropriate confidentiality agreement or protective order. Please contact Beth Herriman at (317) 838-1254 for more information.

3. CO_2 Allowance Price Forecasts

Figure D-2 contains the CO_2 allowance price forecast used in the development of this IRP.

Figure D-2

CO_2 Price Forecasts Nominal $/Ton	
Year	Annual CO_2
2013	0
2014	0
2015	0
2016	0
2017	0
2018	0
2019	0
2020	17
2021	19
2022	21
2023	22
2024	24
2025	26
2026	28
2027	31
2028	33
2029	36
2030	39
2031	43
2032	46
2033	50

4. IRP PVRR

The 2013 Present Value Revenue Requirement (PVRR) obtained from the Planning and Risk (PaR) output for the selected plan is \$51.4 billion or \$0.092/kWh on a 40 year basis, and \$33.9 billion or \$0.080/kWh on a 20 year basis. The following table shows the details.

TIME PERIOD	40 YEAR		20 YEAR	
	PVRR (B\$)	% OF COSTS	PVRR (B\$)	% OF COSTS
CAPITAL	\$10.3	20.0%	\$10.3	30.4%
PRODUCTION	\$27.2	52.9%	\$18.2	53.7%
CO_2	\$13.9	27.1%	\$5.4	15.9%
TOTAL	\$51.4	100%	\$33.9	100%
\$/kwh	\$0.092		\$0.080	

The modeling in PaR does not include the existing rate base (generation, transmission, or distribution). In addition, with the inclusion of estimates of both spot market purchases from, and sales to, the MISO market within the PaR modeling, Present Value Average Rate figures would not accurately reflect projected customer rates, so they have been omitted.

The effective after-tax discount rate used was 6.53%.

5. Impact of a Planned Addition on Rates

Information concerning the impact of each individual planned resource addition by itself is not available because an IRP, by definition, is an <u>integrated combination</u> of resources which together provide energy services in a reliable, efficient, and economic manner while factoring in environmental considerations.

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INDIANA

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Appendix E: Short-Term Implementation Plan

PREFACE

This section contains Duke Energy Indiana's plan for implementing supply-side resources and energy efficiency program resources over the next several years. The supply-side resources are forecast for the period 2013 through 2018. As explained herein, the energy efficiency resources to be implemented by Duke Energy Indiana are forecast through 2014.

APPENDIX E – Table of Contents

SHORT-TERM IMPLEMENTATION PLAN

1. Supply-Side

Edwardsport Integrated Gasified Combined Cycle (IGCC) Project

Project Description

The 2003 IRP indicated a need for coal-fired base load capacity generally beginning in the 2013 timeframe. The 2005 IRP indicated that need beginning 2011, whereas the 2007 IRP indicated the need in 2012. The Edwardsport IGCC re-uses an existing power plant location for the new facility. The approximately 160 MW of existing steam generation capability consisting of three units that entered service during the mid-1940s to the early 1950s was retired in March 2011. Duke Energy Indiana was awarded a CPCN for this project in Cause Nos. 43114 and 43114-S1 in November 2007.

Time Frame

The Edwardsport IGCC Plant was declared in-service on June 7, 2013, upon completion of certain operational milestones. The Company completed the swap out of the instrumented rotor with the permanent rotor on combustion turbine/generator #1 in May 2013, which was the final milestone.

Planned Purchases

Purchases
2013 - 2016

Year	Company	Purchase Type	MW(1)
2013	Benton Cty. Wind	Renewable (Wind)	100 (2)
2014	Benton Cty. Wind	Renewable (Wind)	100 (2)
2015	Benton Cty. Wind	Renewable (Wind)	100 (2)
2016	Benton Cty. Wind	Renewable (Wind)	100 (2)

NOTES: (1) Rounded to the nearest full MW
(2) 9 MW assumed capacity value at the time of summer peak

Additionally, Duke Energy Indiana routinely executes energy hedge trades which provide Duke Energy Indiana price certainty and reduce customers' exposure to energy price volatilities.

2. Environmental Compliance

Duke Energy Indiana Phase 1 CAIR/CAMR Compliance

Project Description

Duke Energy Indiana has added SO_2 control technologies to some of its existing generating units as part of its compliance strategy with the Clean Air Interstate Rule (CAIR) which was finalized in early 2005 by US EPA. In addition, in response to the NO_x provisions of the CAIR, the existing SCR NO_x controls on five of Duke Energy Indiana's generating units were required to operate annually beginning in 2009.

Goal of Project

The goal of the project is to comply with applicable Federal and State environmental requirements, and continue to reliably supply low-cost energy to customers.

Criteria and Objective for Monitoring Success

The success of the projects is determined based upon performance as measured by emission removal efficiency of the equipment, compliance to the budget and emission allowance trading provisions of the rules, and project budget and schedule.

Anticipated Time Frame and Estimated Costs

Compliance with the CAIR NO_x regulations began in 2009 and compliance with the CAIR SO_2 regulations began in 2010. Duke Energy Indiana completed its CAIR Phase 1 construction program in the fall of 2008. The remaining expenditures related to Phase 1 efforts are generally related to completing land-fill additions and/or expansions associated with the emission control equipment additions, as well as performing ongoing SCR catalyst replacement projects. Estimates are indicated below. For jointly-owned Gibson Unit 5, only the capital budgeted to be spent by Duke Energy Indiana is included, *i.e.*, Duke Energy Indiana's share.

	Estimated Capital Costs, 2013 IRP	Estimated Capital Costs, 2011 IRP
2014	$8.5 million	$3.9 million
2015	$4.9 million	$ 2.7 million
2016	$5.7 million	$ 5.8 million
2017	$4.5 million	
2018	$6.7 million	

As discussed in Duke Energy Indiana's Environmental Cost Recovery filings, the costs may vary from the amounts indicated, depending on fluctuations in material prices, labor availability, construction program cost savings, and project scheduling. There was no significant deviation from the execution of this plan as discussed in the 2011 IRP. Duke Energy Indiana continues to optimize SCR catalyst replacement timing based on actual performance and need (resulting in some project deferrals from the prior period), as well as the mix of regenerated and new catalyst purchased.

Phase 2 and 3 Utility Mercury and Air Toxics Standards Rule Compliance Planning

Project Description

Duke Energy Indiana is currently in the process of adding SCRs to Cayuga Units 1 and 2, and related sorbent/chemical injection systems to Cayuga and Gibson as part of its Phase 2 compliance strategy with the Mercury and Air Toxics Standards Rule (MATS) which was finalized in 2012 by US EPA. Further additional expenditures are projected under the Phase 3 MATS compliance plan to complete the MATS compliance strategy, including some additional chemical additive systems, MATS emission monitors, and precipitator refurbishments at Gibson Units 3, 4, and 5. Relative to the short term implementation plan discussed in the 2011 IRP, the MATS compliance costs have decreased significantly due to several positive changes in the Final MATS rule relative to the proposed MATS rule, including the elimination of condensable particulate matter requirements, and the option to demonstrate compliance with the non-mercury metals requirements via filterable particulate matter. This has lead to the elimination of the need for baghouse installations, resulting in the acceleration of the installation of SCRs at Cayuga, and the refurbishment of the existing precipitators at some of the Gibson units. Duke Energy Indiana has also conducted testing showing that no additional mercury controls are need at Gallagher.

Results of and/or delays in other EPA rulemakings have lead to even further reductions in anticipated costs in the short term. EPA has continued to delay issuing a final Coal Combustion Residuals Rule, and a final 316(b) intake structures rule. The Steam Electric Effluent Limitations Guidelines revisions were only recently proposed. EPA did not complete its mid-cycle review of the National Ambient Air Quality Standard for Ozone, delaying implementation of potential reductions from the next review cycle by several years. Lastly, EPA has issued initial final non-attainment designations for the 1-hour SO_2 NAAQS, and Gibson was not identified as non-attainment; this eliminates any near-term risk for replacing the Gibson Unit 5 scrubber. Given these delays and continued uncertainty in the outcome and timing of these regulations, the potential costs of these future regulations are not reflected in this 2013 IRP Short Term Implementation Plan. As rules become finalized and when sufficient confidence exists, Duke Energy Indiana would present required projects to the Commission for appropriate review and approval.

Goal of Project

The goal of the project is to comply with applicable Federal and State environmental requirements, and continue to reliably supply low-cost energy to customers.

Criteria and Objective for Monitoring Success

The success of the projects is determined based upon performance as measured by emission removal efficiency of the equipment, and project budget and schedule.

Anticipated Time Frame and Estimated Costs

The MATS rule compliance date is 4/16/2015. The construction of the proposed projects for MATS rule compliance will generally be completed by this time to comply with the MATS rule. This is an extraordinarily short timeframe to implement a large construction program, especially at Cayuga with the construction of SCRs. Duke Energy Indiana has sought relief under the provision of the MATS rule allowing a one year extension of time for compliance; extensions of time have been received for Cayuga, and Gibson Unit 5, consistent with project implementation schedules and outage schedules on those units.

The estimated capital expenditures are indicated below. For jointly-owned Gibson Unit 5, only the capital budgeted to be spent by Duke Energy Indiana is included, *i.e.*, Duke Energy Indiana's share.

	Estimated Capital Costs, 2013 IRP	Estimated Capital Costs, 2011 IRP*
2014	$240 million	$399.1 million
2015	$98 million	$474.3 million
2016	$2 million	$263.1 million
2017	$2 million	
2018	$0 million	

*Included costs for other air, water, and waste regulations besides MATS rule compliance

Also see Chapter 6 for information related to environmental compliance planning.

3. <u>Energy Efficiency</u>

For 2013 and beyond, Duke Energy Indiana's Energy Efficiency (EE) program portfolio reflects the implementation of the Core Programs offered by the statewide Third Party Administrator and the Core Plus Programs offered by Duke Energy Indiana.

Duke Energy Indiana estimates that it will spend approximately $45.2 million dollars in 2013 implementing the Core and Core Plus EE Programs along with $11.2 million dollars for the Demand Response Programs. An estimate of the 2013 and 2014 charges for each of the EE programs in the Core and Core Plus portfolios and the Demand Response Programs is provided in a Table STIP-1 located at the end of this STIP.

EE Programs Historically Offered By Duke Energy Indiana

Duke Energy Indiana has a long history associated with the implementation of energy efficiency programs. Duke Energy Indiana's energy efficiency programs are designed to help reduce demand on the Duke Energy Indiana system during times of peak load and reduce energy consumption during peak and off-peak hours. The programs fall into two categories: traditional energy efficiency programs and demand response programs. Demand response programs contain customer-specific contract curtailment options, the Power Manager (residential direct load control) program, and the PowerShare® program (for non-residential customers). Implementing cost-effective energy efficiency and demand response programs helps reduce overall long-term supply costs. Duke Energy Indiana's energy efficiency programs are primarily selected for implementation based upon their appeal to Duke Energy Indiana customers and cost-effectiveness; however, there may be programs, such as a low income program, that are chosen for implementation due to desirability from an educational and/or societal perspective.

Since 1991, Duke Energy Indiana has offered a variety of energy efficiency programs that create significant savings to customers. These programs have been approved over the last several years through a variety of Commission Orders and will continue to be offered until replaced in the near future by programs as mandated by the Commission and as requested by Duke Energy Indiana.

Current Programs

Duke Energy Indiana intends to continue to be a leader in energy efficiency by offering programs through a combination of programs to be offered by a Third Party Administrator (Core Programs) and programs offered by Duke Energy Indiana (Core Plus Programs).

In July 2013, Duke Energy Indiana filed an application to extend the Core Plus programs approved in Cause 43955 for another year through the end of 2014. In addition, Duke

Energy Indiana asked for approval to begin offering a new pilot program, Energy Management Information Services, to convert a Pilot program (Home Energy Comparison Report) to commercial operations and to expand the Non-Residential Smart Saver program with the addition of several new measures.

Some measures that were previously offered as Core Plus programs will be moving to the Core programs effective January 1, 2015, including Appliance Recycling and certain Commercial and Industrial measures.

General Objective

Through a combination of the Core and Core Plus programs, Duke Energy Indiana expects to reduce energy and demand through the implementation of a broad set of energy efficiency programs. These programs will be available for both residential and non-residential customers and include both energy efficiency and demand response programs. Demand response programs contain customer-specific contract curtailment options: Power Manager (residential direct load control), and PowerShare® (for non-residential customers).

Criteria for Measuring Progress

Evaluation, Measurement, and Verification (EM&V) studies will be undertaken to measure the impacts achieved from the implementation of the proposed programs. For the Core Programs, EM&V will be conducted by the statewide evaluator and for the Core Plus Programs, the EM&V will be conducted by an independent contractor employed by Duke Energy Indiana. The timetable for implementation of the programs and the EM&V analyses will depend upon the timing of the deployment of the Core Programs by the Third Party Administrator and the timing of the deployment of the Core Plus Programs offered by Duke Energy Indiana.

Program Descriptions:

The details of the Core and Core Plus Programs are included in Chapter 4, Section E.

Table E-1 Projected Program Expenditures (STIP-1)

TABLE STIP - 1

Projected Program Expenditures

Core Programs	**2013**	**2014**
Residential Lighting	$ 2,989,627	$ 336,571
Home Energy Audit	$ 5,369,443	$ 2,640,089
Low Income Weatherization	$ 2,162,439	$ 2,055,332
Energy Efficient Schools	$ 3,812,551	$ 3,494,668
School Assessments	$ 390,000	$ 195,000
Comercial and Industrial	$ 15,245,198	$ 18,265,271
Total Core	**$ 29,969,257**	**$ 26,986,930**

Core Plus Programs	**2013**	**2014**
Personalized Energy Report	$ 800,535	$ -
Smart Saver Residential	$ 2,732,872	$ 1,474,721
Agency CFLs	$ 354,621	$ 135,079
Refrigerator and Freezer Recycling	$ 957,642	$ 466,231
Property Manager CFL	$ 258,488	$ 168,072
Tune and Seal	$ 1,587,285	$ 427,256
Home Energy Comparison Report	$ 1,007,607	$ 1,859,372
Power Manager	$ 2,524,781	$ 2,486,903
EMIS (Pilot)	$ -	$ 388,620
Smart Saver Non-Residential	$ 7,573,003	$ 6,834,305
Non-Residential Energy Assessments[1]	N/A	N/A
Power Share Call Option	$ 8,663,777	$ 9,988,109
Total Core Plus	**$ 26,460,611**	**$ 24,228,668**

Total EE/DR Programs	**$ 56,429,869**	**$ 51,215,598**

1 - Costs associated with Non-Residential Energy Assessments are included within the Smart Saver Non-Residential Programs

4. Transmission and Distribution

The transmission and distribution information is located in Appendix G of this report.

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Appendix F:
Standardized Templates

APPENDIX F – Table of Contents

Table F
Supply vs Demand Balance

DUKE ENERGY INDIANA
SUPPLY VS. DEMAND BALANCE
(Summer Capacity and Loads)

YEAR	Owned Capacity[a] (MW)	Incremental Purchases (MW)	Incremental Capacity Additions (MW)	Incremental Capacity Retirements/ Derates[b] (MW)	Incremental Behind The Meter Generation (MW)	Total Capacity (MW)	Peak Load[c] (MW)	Conservation[d] (MW)	Demand Response (MW)	Net Load (MW)	Reserve Margin (%)	NOTES
2013	7706	9	0	0	18	7733	6542	-26	-502	6015	28.6	
2014	7733	0	0	-350	0	7383	6686	-77	-528	6081	21.4	Wabash River 2-5 retirement
2015	7383	0	0	-316	0	7067	6555	-140	-549	5866	20.5	Gibson 5 Backstand Contract Expiration
2016	7067	0	318	-318	0	7067	6746	-213	-568	5965	18.5	Wabash River 6 natural gas conversion
2017	7067	0	0	0	0	7067	6876	-299	-577	5999	17.8	
2018	7067	0	29	-166	0	6930	6998	-392	-587	6019	15.1	Connersville and Miami Wabash retirement, Renewable
2019	6930	0	217	-280	0	6867	7083	-496	-587	6000	14.4	Gallagher 2 and 4 retirement
2020	6867	0	215	0	0	7082	7203	-551	-587	6065	16.8	New CT, Renewable
2021	7082	0	17	0	0	7099	7301	-560	-587	6154	15.3	New CT, Renewable
2022	7099	0	15	0	0	7114	7399	-567	-587	6246	13.9	Renewable
2023	7114	0	213	0	0	7327	7499	-575	-587	6338	15.6	New CT, Renewable
2024	7327	0	18	0	0	7345	7569	-549	-587	6433	14.2	Renewable
2025	7345	0	224	0	0	7569	7699	-589	-587	6523	16.0	New CT, Renewable
2026	7569	0	52	0	0	7621	7798	-597	-587	6615	15.2	Renewable
2027	7621	0	342	0	0	7963	7891	-604	-587	6700	18.9	New CC, Renewable
2028	7963	-9	0	0	0	7954	7963	-577	-587	6799	17.0	Benton County PPA expiration
2029	7954	0	0	0	0	7954	8061	-586	-587	6888	15.5	
2030	7954	0	340	0	0	8294	8195	-593	-587	7015	18.2	New CC
2031	8294	0	302	-318	0	8278	8297	-635	-587	7075	17.0	New Nuclear, Renewable, Wabash River 6 retirement
2032	8278	0	54	0	0	8332	8403	-641	-587	7175	16.1	Renewable
2033	8332	0	63	0	0	8395	8485	-615	-587	7284	15.3	Renewable

Notes:

[a] Including Gibson 5 capacity owned by IMPA and WVPA through 12/31/14
20MW derate to serve steam to Premier Boxboard has been deducted

[b] Reflects expiration of Gibson 5 back-up to IMPA and WVPA 12/31/14

[c] Including IMPA and WVPA peak load requirements corresponding to their Gibson 5 ownership through 12/31/14

[d] Not already included in load forecast. This value is coincident with the net peak load, so it may not be the peak value for the year.

Table F-2
Peak and Energy Forecast

	Summer Peak (MW)	Winter Peak (MW)	Annual Peak (MW)	Annual Energy (MWh)	Load Factor (%)
2013	6,516	6,233	6,516	36,105,386	63.3%
2014	6,609	6,160	6,609	36,431,641	62.9%
2015	6,415	5,966	6,415	34,633,582	61.6%
2016	6,533	5,963	6,533	35,205,197	61.5%
2017	6,577	5,915	6,577	35,400,413	61.4%
2018	6,606	5,865	6,606	35,308,109	61.0%
2019	6,587	5,833	6,587	35,132,201	60.9%
2020	6,652	5,835	6,652	35,243,015	60.5%
2021	6,741	5,878	6,741	35,600,217	60.3%
2022	6,832	5,936	6,832	36,004,012	60.2%
2023	6,924	5,935	6,924	36,413,932	60.0%
2024	7,019	5,936	7,019	36,832,568	59.9%
2025	7,110	5,991	7,110	37,233,927	59.8%
2026	7,202	5,967	7,202	37,637,926	59.7%
2027	7,287	6,043	7,287	38,008,211	59.5%
2028	7,386	6,070	7,386	38,410,380	59.4%
2029	7,474	6,038	7,474	38,792,161	59.2%
2030	7,602	6,070	7,602	39,195,890	58.9%
2031	7,662	6,145	7,662	39,602,664	59.0%
2032	7,761	6,171	7,761	40,027,500	58.9%
2033	7,871	6,220	7,871	40,445,289	58.7%
Compound Average Growth Rate	0.9%	0.0%	0.9%	0.6%	

Table F-3: Duke Energy Indiana
Summary of Existing Electric Generating Facilities

Plant Name	Unit Number	City or County	State	In-Service Year	Unit Type	Primary Fuel	Secondary Fuel (if any)	Ownership %	Winter Rating (MW)	Summer Rating (MW)	Environmental Controls	Notes
Cayuga	1	Cayuga	IN	1970	ST	Coal		100.00%	505.0	500.0	FGD, EP, LNB, OFA, CT (SCR, DSI – 2014)	SCR and DSI under construction
Cayuga	2	Cayuga	IN	1972	ST	Coal		100.00%	500.0	495.0	FGD, EP, LNB, OFA, CT (SCR, DSI – 2015)	SCR and DSI under construction
Cayuga	3A	Cayuga	IN	1972	IC	Oil		100.00%	3.0	3.0	None	
Cayuga	3B	Cayuga	IN	1972	IC	Oil		100.00%	3.0	3.0	None	
Cayuga	3C	Cayuga	IN	1972	IC	Oil		100.00%	3.0	2.0	None	
Cayuga	3D	Cayuga	IN	1972	IC	Oil		100.00%	2.0	2.0	None	
Cayuga	4	Cayuga	IN	1993	CT	Gas	Oil	100.00%	120.0	99.0	DLN (Gas); WI (Oil)	
Connersville	1	Connersville	IN	1972	CT	Oil		100.00%	49.0	43.0	None	
Connersville	2	Connersville	IN	1972	CT	Oil		100.00%	49.0	43.0	None	
Edwardsport	IGCC	Knox County	IN	2013	IGCC	Syngas	Gas	100.00%	630.0	595.0	Selexol, SCR, MGB, CT	
Gallagher	2	New Albany	IN	1958	ST	Coal		100.00%	140.0	140.0	BH, LNB, OFA, DSI	DSI required by Consent Decree
Gallagher	4	New Albany	IN	1961	ST	Coal		100.00%	140.0	140.0	BH, LNB, OFA, DSI	DSI required by Consent Decree
Gibson	1	Owensville	IN	1976	ST	Coal		100.00%	635.0	630.0	FGD, SCR, SBS, EP, LNB, OFA, CL	
Gibson	2	Owensville	IN	1975	ST	Coal		100.00%	635.0	630.0	FGD, SCR, SBS, EP, LNB, OFA, CL	
Gibson	3	Owensville	IN	1978	ST	Coal		100.00%	635.0	630.0	FGD, SCR, SBS, EP, LNB, OFA, CL	
Gibson	4	Owensville	IN	1979	ST	Coal		100.00%	627.0	622.0	FGD, SCR, SBS, EP, LNB, OFA, CL	
Gibson	5	Owensville	IN	1982	ST	Coal		50.05%	312.8	310.3	FGD, SCR, SBS, EP, LNB, OFA, CL	Jointly owned with WVPA (25%) and IMPA (24.95%)
Henry County	1	Henry County	IN	2001	CT	Gas		100.00%	43.0	43.0	WI	50 MW from the plant is supplied to load other than DEI under PPA
Henry County	2	Henry County	IN	2001	CT	Gas		100.00%	43.0	43.0	WI	
Henry County	3	Henry County	IN	2001	CT	Gas		100.00%	43.0	43.0	WI	
Madison	1	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	2	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	3	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	4	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	5	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	6	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	7	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Madison	8	Butler County	OH	2000	CT	Gas		100.00%	88.0	72.0	DLN	
Markland	1	Florence	IN	1967	HY	Water		100.00%	15.0	15.0	None	
Markland	2	Florence	IN	1967	HY	Water		100.00%	15.0	15.0	None	
Markland	3	Florence	IN	1967	HY	Water		100.00%	15.0	15.0	None	

[1] Edwardsport IGCC capacity ratings are preliminary pending ongoing program performance testing. The summer capacity reflects evaporative coolers in service.

Table F-3: Duke Energy Indiana
Summary of Existing Electric Generating Facilities

Plant Name	Unit Number	City or County	State	In-Service Year	Unit Type	Primary Fuel	Secondary Fuel (if any)	Ownership %	Winter Rating (MW)	Summer Rating (MW)	Environmental Controls	Notes
Miami-Wabash	1	Wabash	IN	1968	CT	Oil		100.00%	17.0	16.0	None	
Miami-Wabash	2	Wabash	IN	1968	CT	Oil		100.00%	17.0	16.0	None	
Miami-Wabash	3	Wabash	IN	1968	CT	Oil		100.00%	17.0	16.0	None	
Miami-Wabash	5	Wabash	IN	1969	CT	Oil		100.00%	17.0	16.0	None	
Miami-Wabash	6	Wabash	IN	1969	CT	Oil		100.00%	17.0	16.0	None	
Noblesville	1	Noblesville	IN	1950	ST in CC			100.00%	46.0	46.0	CT	Units 1 & 2 were repowered as Gas CC in 2003
Noblesville	2	Noblesville	IN	1950	ST in CC			100.00%	46.0	46.0	CT	Units 1 & 2 were repowered as Gas CC in 2003
Noblesville	3	Noblesville	IN	2003	CT in CC	Gas		100.00%	72.7	64.4	DLN, SCR, CO	CT and share of HRSG capacity combined
Noblesville	4	Noblesville	IN	2003	CT in CC	Gas		100.00%	72.7	64.4	DLN, SCR, CO	CT and share of HRSG capacity combined
Noblesville	5	Noblesville	IN	2003	CT in CC	Gas		100.00%	72.7	64.4	DLN, SCR, CO	CT and share of HRSG capacity combined
Vermillion	1	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	2	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	3	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	4	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	5	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	6	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	7	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Vermillion	8	Cayuga	IN	2000	CT	Gas		62.5%	55.6	44.4	DLN	Jointly owned with WVPA
Wabash River	2	West Terre Haute	IN	1953	ST	Coal		100.00%	85.0	85.0	EP, LNB, OFA	
Wabash River	3	West Terre Haute	IN	1954	ST	Coal		100.00%	85.0	85.0	EP, LNB, OFA	
Wabash River	4	West Terre Haute	IN	1955	ST	Coal		100.00%	85.0	85.0	EP, LNB, OFA	
Wabash River	5	West Terre Haute	IN	1956	ST	Coal		100.00%	95.0	95.0	EP, LNB, OFA	
Wabash River	6	West Terre Haute	IN	1968	ST	Coal		100.00%	318.0	318.0	EP, LNB, OFA	
Wabash River	7A	West Terre Haute	IN	1967	IC	Oil		100.00%	3.1	3.1	None	
Wabash River	7B	West Terre Haute	IN	1967	IC	Oil		100.00%	3.1	3.1	None	
Wabash River	7C	West Terre Haute	IN	1967	IC	Oil		100.00%	2.1	2.1	None	
Wheatland	1	Knox County	IN	2000	CT	Gas		100.00%	122.0	115.0	WI	
Wheatland	2	Knox County	IN	2000	CT	Gas		100.00%	122.0	115.0	WI	
Wheatland	3	Knox County	IN	2000	CT	Gas		100.00%	122.0	115.0	WI	
Wheatland	4	Knox County	IN	2000	CT	Gas		100.00%	122.0	115.0	WI	
Total									7,871.0	7,494.0		

Unit Type

ST	Steam
CT	Simple Cycle Combustion Turbine
CC	Combined Cycle Combustion Turbine
IC	Internal Combustion
HY	Hydro
IGCC	Integrated Coal Gasification Combined Cycle

Fuel Type

Coal
Gas
Syngas
Oil
Water

Environmental Controls

FGD	SO_2 Scrubber
SCR	Selective Catalytic Reduction
SBS	Sodium Bisulfite / Soda Ash Injection System
LNB	Low NO_x Burner
EP	Electrostatic Precipitator
BH	Baghouse
CT	Cooling Tower
CL	Cooling Lake
WI	Water Injection (NO_x)
OFA	Overfire Air
CO	Passive Carbon Monoxide Catalyst
DSI	Dry Sorbent Injection
MGB	Mercury Guard Carbon Bed
DLN	Dry Low NO_x Combustion System
Selexol	Acid-Gas removal technology

Table F-4
Duke Energy Indiana
Summary of Existing Electric Generating Facilities by Plant

	Winter (MW)	Summer (MW)
Cayuga	1,136	1,104
Connersville	98	86
Edwardsport	630	595
Gallagher	280	280
Gibson	2,844.8	2,822.3
Henry County	129	129
Madison	704	576
Markland	45	45
Miami-Wabash	85	80
Noblesville	310.1	285.2
Vermillion	444.8	355.2
Wabash River	676.3	676.3
Wheatland	488	460
Grand Total	**7,871.0**	**7,494.0**

Table F-5
Duke Energy Indiana
Summary of Existing Electric Generating Facilities by Fuel

	Winter (MW)	Summer (MW)	Winter % of Total Capacity	Summer % of Total Capacity
Coal	**4,797.8**	**4,765.3**	**61.0%**	**63.6%**
Cayuga	1,005.0	995.0		
Gallagher	280.0	280.0		
Gibson	2,844.8	2,822.3		
Wabash River	668.0	668.0		
Syngas	**630.0**	**595.0**	**8.0%**	**7.9%**
Edwardsport	630.0	595.0		
Gas	**2,195.9**	**1,904.4**	**27.9%**	**25.4%**
Cayuga	120.0	99.0		
Henry County	129.0	129.0		
Madison	704.0	576.0		
Noblesville	310.1	285.2		
Vermillion	444.8	355.2		
Wheatland	488.0	460.0		
Oil	**202.3**	**184.3**	**2.5%**	**2.5%**
Cayuga	11.0	10.0		
Connersville	98.0	86.0		
Miami-Wabash	85.0	80.0		
Wabash River	8.3	8.3		
Water	**45.0**	**45.0**	**0.6%**	**0.6%**
Markland	45.0	45.0		
Grand Total	**7,871.0**	**7,494.0**		

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The Duke Energy Indiana
2013 Integrated Resource Plan

November 1, 2013

Appendix G:
Transmission Planning and Forecast

PREFACE

References to the combined transmission systems of Duke Energy Ohio and Duke Energy Kentucky will be labeled as Duke Energy Ohio. References to the combined transmission systems of Duke Energy Indiana and Duke Energy Ohio will be labeled as Duke Energy Midwest. In addition, the Figures associated with each chapter or section of the appendix are located at the end of that chapter or section of the appendix for convenience.

APPENDIX G - Table of Contents

1. TRANSMISSION EXECUTIVE SUMMARY

A. System Description

The Duke Energy Midwest bulk transmission system is comprised of the 345 kilovolt (kV), and 138 kV systems of Duke Energy Ohio and the 345 kV, 230 kV, and 138 kV systems of Duke Energy Indiana. The transmission system serves primarily to deliver bulk power into and/or across Duke Energy Midwest's service area. This bulk power is distributed to numerous substations that supply lower voltage sub-transmission systems and distribution circuits, or directly to large customer loads. Because of the numerous interconnections Duke Energy Midwest has with neighboring local balancing areas, the Duke Energy Midwest transmission system increases electric system reliability and decreases costs to customer by permitting the exchange of power and energy with other utilities on an emergency or economic basis.

As of December 2012, Duke Energy Indiana's wholly and jointly owned share of bulk transmission included approximately 721 circuit miles of 345 kV lines, 645 circuit miles of 230 kV lines and 1402 circuit miles of 138 kV lines. Duke Energy Indiana, Indiana Municipal Power Agency (IMPA), and Wabash Valley Power Association (WVPA) own the Joint Transmission System (JTS) in Indiana. The three co-owners have rights to use the JTS. Duke Energy Indiana is directly interconnected with seven other local balancing authorities (American Electric Power, Louisville Gas and Electric Energy, Ameren, Hoosier Energy, Indianapolis Power and Light, Northern Indiana Public Service Company, and Vectren) plus Duke Energy Ohio.

Portions of the Duke Energy Ohio 345 kV bulk transmission system are jointly owned with Columbus Southern Power (CSP) and/or Dayton Power & Light (DP&L). As of December, 2012, the bulk transmission system of Duke Energy Ohio and its subsidiary companies consisted of approximately 403 circuit miles of 345 kV lines (including Duke Energy Ohio's share of jointly-owned transmission) and 726 circuit miles of 138 kV lines. Duke Energy Ohio is directly connected to five local balancing authorities (American Electric Power, Dayton

Power and Light, East Kentucky Power Cooperative, Louisville Gas and Electric Energy, Ohio Valley Electric Cooperative) plus Duke Energy Indiana.

B. <u>Electric Transmission Forecast</u>

As a member of the Midcontinent Independent System Operator, Inc. (MISO), Duke Indiana participates in the MISO planning processes, and is subject to the overview and coordination mechanisms of the MISO. All of Duke Energy Indiana's transmission facilities, including those transmission facilities owned by WVPA and IMPA but operated and maintained by Duke Energy Indiana, are encompassed in these MISO planning processes. Additional coordination occurs through a variety of mechanisms, including Reliability*First* Corporation (RFC) and joint meetings with the other entities held as necessary.

2. ELECTRIC TRANSMISSION FORECAST

A. General Description

The Duke Energy Midwest bulk transmission system is comprised of 138 kV, 230 kV, and 345 kV systems. The 345 kV system generally serves to distribute power from Duke Energy Midwest's large generating units on the system, and to interconnect the Duke Energy Midwest system with other systems. These interconnections enable the transmission of power between systems from jointly owned generating units and they provide capacity for economy and emergency power transfers. The 345 kV system is connected to the 138 kV and 230 kV systems through large transformers at a number of substations across the system. These 138 kV and 230 kV systems generally distribute power received through the transformers and also from several smaller generating units, which are connected directly at these voltage levels. This power is distributed to substations, which supply lower voltage sub-transmission systems and distribution circuits, or directly to a number of large customer loads.

B. Transmission and Distribution Planning Process

Transmission and distribution planning is a complex process which requires the evaluation of numerous factors to provide meaningful insights into the performance of the system. Duke Energy Midwest's distribution system planners gather information concerning actual distribution substation transformer and line loadings. The loading trend for each transformer is examined, and a projection of future transformer bank loading is made based on the historic load growth combined with the distribution planners' knowledge of load additions within the area. The load growth in a distribution planning area tends to be somewhat more uncertain and difficult to predict than the load forecasts made for Duke Energy Midwest as a whole.

Customers' decisions can dramatically impact not only the location of future distribution capacity, but also the timing of system improvement projects. Because of this uncertainty, distribution development plans must be under continual review to make sure the proposed specific projects remain appropriate for the area's needs.

Transmission and distribution (T&D) planning generally depends on the specific location of the loads, therefore the effects of co-generation capacity on T&D planning is location-specific. To the extent that fewer new T&D resources are required to serve these customers or the local areas in which they reside, Duke Energy Midwest's T&D planning will reflect this change.

It typically takes 18 to 24 months to add new distribution substation capacity to an area. Factors closely related to the future customer's load, such as local knowledge of growth potential based upon zoning, highway access and surrounding development can help forecast ultimate distribution system needs.

The transmission system planners utilize the historical distribution substation transformer bank loading and trends, combined with the Duke Energy Midwest load forecast and resource plan and firm service schedules, to develop models of the transmission system. These models are used to simulate the transmission system performance under a range of credible conditions to ensure that the expected performance of the transmission system meets both North American Electric Reliability Corporation (NERC) and Duke Energy Indiana planning criteria. Should these simulations indicate that a violation of the planning criteria occurs, more detailed studies are conducted to determine the severity of the problem and possible measures to alleviate it.

Duke Energy Indiana's planning criteria are filed under the **FERC FORM 715 Part 4** and described as follows. The Company adheres to any applicable NERC and RFC Reliability Standards. The Company also has its own detailed planning criteria, which are shown in the following paragraphs. Violations of these criteria would result in one or several of the following actions: expansion of transmission system; operating procedures; or a combination of the two. Acceptance of operating procedures is based on engineering judgment with the consideration of the probability of violation weighed against its consequences and possibly other factors.

Voltage

Bus voltages are screened using the Transmission System Voltage Limits below. These Limits specify minimum and maximum voltage levels during both normal and contingency conditions. Emergency Voltage Limits are defined as the upper and lower operating limits of each bus on the system. The voltage limits are expressed as a percent of the nominal voltage. All voltages should be maintained within the appropriate Emergency voltage limits.

Transmission System Voltage Limits

Nominal Voltage (kV)	Normal Voltage Limits Minimum	Normal Voltage Limits Maximum	Emergency Voltage Limits Minimum	Emergency Voltage Limits Maximum
345	95%	105%	90%	105%
230	95%	107%	90%	107%
138	95%	105%	90%	105%

Thermal

The following guidelines shall be used to ensure acceptable thermal loadings:

a) In normal conditions, no facility should exceed its continuous thermal loading capability.

b) For a single contingency no facility should exceed its emergency loading capability.

Stability

The stability of the Duke Energy Indiana system and neighboring systems must be maintained for the contingencies specified in the applicable sections of the NERC and RFC Reliability Standards. Generating units must maintain angular stability under various contingency situations. Many different contingencies are considered and the selection is dependent on the location within the transmission system.

Fault Duty

All circuit breakers should be capable of interrupting the maximum fault current duty imposed on the circuit breaker.

Single Contingencies

The thermal and voltage limits should not be violated for either normal operations or under the loss of:

a) A single transmission circuit

b) A single transformer

c) A single generating unit

d) A single reactive power source or sink

Severe Contingencies

NERC Reliability Standards instruct transmission planners to evaluate extreme (highly improbable) contingency events resulting in multiple elements removed or cascading out of service. Severe contingencies are evaluated to determine the impact on the transmission system and on the surrounding interconnected transmission system. The severity of the consequences, availability of emergency switching procedures, probability of occurrence and the cost of remedial action will be considered in the evaluation of these severe contingencies

These planning criteria are not intended to be absolute or applied without exception. Other factors, such as severity of consequences, availability of emergency switching procedures, probability of occurrence and the cost of remedial action are also considered in the evaluation of the transmission system.

C. <u>System-Wide Reliability Measure</u>

At the present time, there is no measure of system-wide reliability that covers the entire system (transmission, distribution, and generation).

D. <u>Evaluation of Adequacy for Load Growth</u>

The transmission system of Duke Energy Midwest is adequate to support load growth and the expected power transfers over the next ten years. This assumes that the planned transmission system expansions are completed as currently scheduled. See Section G in this Appendix for details on the major planned transmission projects. Duke Energy Midwest's transmission system, as with the transmission system of any other utility, can be significantly affected by the actions of others. In an attempt to evaluate these effects, RFC develops a series of power flow simulation base cases that reflect the expected transmission system configuration and expected power transfers. Should actual conditions differ significantly from those assumed in the base cases, a re-evaluation of the adequacy of the Duke Energy Midwest transmission system would be required.

E. <u>Economic/Loss Evaluation</u>

As a member of MISO, Duke Energy Indiana actively participates in the MISO Transmission Expansion Planning (MTEP) assessment and study processes which include economic analysis. MISO utilizes PROMOD, a commercial production cost model, to evaluate potential economic benefits of transmission projects or portfolios. Production cost model simulations are performed with and without each developed transmission project or portfolio. Taking the difference between these two cases provides the economic benefits associated with each project or portfolio. The economic benefits identified in analysis include adjusted production cost savings, reduced energy and capacity losses, and reduced congestion cost. Projects that meet initial qualification criteria will be further evaluated under the appropriate MISO or interregional planning process.

F. <u>Transmission Expansion Plans</u>

The transmission system expansion plans for the Duke Energy Midwest system are developed for the purpose of meeting the projected future requirements of the transmission system. The basic methodology used to determine the future requirements is power flow analysis. Power flow representations of the Duke Energy Midwest electric transmission system, which allow computer simulations to determine MW and MVAR flows and the voltages across the system, are maintained for the peak periods of the current year and for future years. These power flow base cases simulate the system under normal conditions with typical generation, and no transmission outages. They are used to determine the general performance of the existing and planned transmission system under normal conditions.

Contingency cases based on the peak load base cases are studied to determine system performance for planned and unplanned transmission and generation outages. The results of these studies are used as a basis to determine the need for and timing of additions to the transmission system. As indicated earlier, Duke Energy Indiana, as a member of the MISO actively participate in the MISO MTEP assessment and study processes by reviewing the modeling data, providing simulation scenarios and reviewing and providing feedback on the results of MTEP assessments and studies. All of Duke Energy Indiana’s transmission facilities, including those transmission facilities owned by WVPA and IMPA but operated and maintained by Duke Energy Indiana, are encompassed in these MISO processes. In addition, MISO reviews Duke Energy Indiana's proposed plans and makes comments and suggestions. Ultimately, the MISO has responsibility for development of the regional transmission plan. The MTEP 12 assessed the Duke Energy Indiana transmission system for the period 2012 through 2022. MTEP 12 simulations were conducted for years 2013, 2016 and 2021. These models were utilized to simulate both steady state and dynamic performance of the transmission system under a wide variety of credible conditions, such as Summer Peak, Shoulder Peak, and Light Load conditions to ensure that the expected performance of the transmission system meets both North American Electric Reliability Corporation (NERC) and Duke Energy Indiana planning criteria.

The MTEP studies provide an indication of system performance under a variety of conditions to guide the development of a comprehensive expansion plan that meets both reliability and economic expansion needs. The planning process identifies solutions to reliability issues that arise from the expected dispatch of Network Resources. These solutions include evaluating alternative costs between capital expenditures for transmission expansion projects, and increased operating expenses from redispatching Network Resources or other operational actions.

G. Transmission Project Descriptions

The following planned transmission projects include new substation transformers, transmission capacitors, transmission circuits, and upgrades of existing circuits and substations.

Duke Energy Indiana plans to continue to install transmission voltage capacitors with over 115.2 MVAR planned on its system over the next three years. The capacitors will be installed at various existing transmission substations at 69 kV and 138 kV voltages throughout the system. These additions will supplement the existing 2571 MVAR that have been installed and are in service thru 2013. These capacitors are necessary to maintain and improve the over-all transmission voltage profile, reduce system losses, improve reactive margin at generating stations and reduce interconnection reactive imports. Higher cost alternatives to capacitor installations include construction of additional transmission system capacity, static VAR compensators, and/or local generation.

The Speed substation is an expansive bulk transmission facility in southern Indiana near Clarksville. This substation has an existing 450 MVA, 345/138 kV power transformer that will need to be upgraded to a 650 MVA unit in the year 2022 based upon anticipated area load growth. This larger Speed substation transformer as well as a new 345 kV interconnection planned with Louisville Gas & Electric and Kentucky Utilities (LG&E/KU) helps supplement the area bulk power flows. A similar transformer capacity addition at an alternate site would involve significant investment in new substation and terminal equipment with land acquisition costs.

A new 345 kV transmission interconnection point with LG&E/KU has been finalized for service in 2014. The new Kenzig Switching Station will be constructed in New Albany within proximity to the Duke Energy Indiana – Ramsey to Speed 345 kV line and the LG&E/KU - Paddys West to Northside 345 kV line. This new interconnection point will provide for normal and contingency power flows to supplement transmission reliability between the two Companies. The new switching station will be constructed and operated by LG&E/KU with Duke Energy Indiana providing minor construction cost participation. This development is considered the lowest cost alternative of several options considered to establish a needed supplemental transmission path between the two systems. The connection's mutual benefits will help ensure the future bulk system operation reliability in southern Indiana. This project will allow delay of the future Speed 345/138 kV transformer replacement project.

A new 230 kV switching station, WestPoint 230 kV, to connect the Tri-County 200 MW wind farm located in Tippecanoe County is planned with in-service date of August 2015. The new switching station will split the existing Veedersburg West to Attica to Lafayette 23027 circuit.

The Lafayette 230 kV substation is a major bulk power delivery facility in Tippecanoe County. This substation has been a part of the bulk power system for many years. Due to age and condition of the 230 kV breakers, a plan has been developed to not only replace and upgrade the breakers with new equipment but also re-arrange the existing straight bus into a ring bus arrangement. The existing straight bus has an inherent concern that a single bus section failure will remove multiple lines and/or transformers from service. The ring bus design circumvents this problem by allowing only a single supply element outage with its associated bus section failure. This then preserves the adjacent bus connected transformers and lines for continued service. Due to the complexity and cost of this effort, the total project is being divided into two phases for completion in 2014 and 2016. The alternative to this project would be to spend on equipment upgrades only, but that retains a past bus design that limits not only reliability, but significantly impedes equipment maintenance due to the difficulty obtaining the required outages of multiple service components at the same time.

An evaluation of service reliability, line ground clearance reviews, and physical condition aspects has directed the decision to totally rebuild and replace an existing 230 kV transmission line between the Tipton West Substation and the Kokomo Highland Park Substation. In addition, this 50 year old line has experienced line galloping and insulator failure problems. The 14 miles of line in Tipton and Howard Counties will be designed with new taller structures and new oval anti-galloping phase conductors. This line is an important link between the Noblesville station and the Kokomo load area with its bulk connected lines. Alternatives to rebuilding this existing line would be a new line with associated new rights of way and required line terminal costs. Then there would be the continued maintenance on the existing line unless there would be spend to retire and remove.

Madison 138 kV substation has been in service over 55 years and is in need of refurbishment due to equipment obsolescence, condition, and inadequate relaying protection issues. All three 138 kV line breakers are being replaced with the addition of new bank breakers, with complete system protection, line, and bank relaying functions being upgraded. Modern equipment will be installed to permit continued reliable service at this substation and the interconnected source lines. Alternatives of continued operation issues and marginal equipment maintenance are not long term solutions.

Due to the expected retirement of Wabash River units 2-5, transmission improvements will be required. The current proposed transmission plan involves the construction of a new 138 kV circuit from Dresser to Wabash River.

The 2013-2015 cash flows associated with these planned major new Duke Energy Indiana transmission facility projects can be found in Section C of the Transmission Short-Term Implementation Plan (STIP).

H. <u>Economic Projects Comments</u>

Duke Energy Indiana continues to stay abreast of MISO expansion criteria and participate in MISO studies and evaluate transmission projects that provide economic value to Duke Energy Indiana customers.

STIP

Planned New Transmission Facilities

Description of Projects

See the tables below for status of previous projects reported as well as a current projects listing. More detailed descriptions of the current projects can be found in Section 2.G of this Appendix.

Criteria and Objectives for Monitoring Success

Milestones and criteria used to monitor the transmission facilities projects are typical of construction projects and measured on the following factors:

- Comparison of the actual completion date to the targeted completion date
- Comparison of the actual cost to the budgeted cost

Anticipated Time Frame and Estimated Costs

The cash flows associated with the major new transmission facility projects planned are shown below.

STATUS UPDATES AND CHANGES FROM PREVIOUS REPORT
DUKE ENERGY INDIANA TRANSMISSION PROJECTS

				CASH FLOWS ($000)		
PROJECT NAME	**MILES or MVA**	**kV**	**PROGRESS/ COMPLETION DATE**	**2011**	**2012**	**2013**
Qualitech Sub add 345/138 kV bank/terminal	200	138	6/1/2013 revised to 12/31/2013 (Note 1)			$2727 Revised $1600 (Note 5)
Qualitech-Pittsboro 138 kV circuit	2.6	138	6/1/2013 revised to 12/31/2013 (Note 2)			$40
Plainfield South Sub 138 kV terminal	-	138	6/1/2013 revised to 12/31/2013 (Note 3)			$548
Crawfordsville – Concord Jct 138 kV line new conductor	17.4	138	12/31/13 completed 1/4/2013 (Note 6)			
Westpoint 230 kV Switching Station	-	230	8/31/2013 revised to 12/31/15 carried to next table (Note 4)			$0
Speed – LGE Paddys West 345kV line interconnection – (Changed description to: Duke- LGE/KU 345 kV Interconnect Kenzig Switching Station)		345	6/1/2014 carried to next table			

CURRENT DUKE ENERGY INDIANA MAJOR TRANSMISSION PROJECTS

				CASH FLOWS ($000)		
PROJECT NAME	**MILES or MVA**	**kV**	**PROGRESS/ COMPLETION DATE**	**2013**	**2014**	**2015**
Duke – LGE/KU 345 kV Interconnect Kenzig Switching Station	-	345	12/31/2014		$400 (Note 7)	
WestPoint 230 kV Switching Station	-	230	12/31/15		$0	$0
Lafayette 230 kV Sub Breaker Repl with Ring Bus Phase 1	-	230	12/31/14	$250	$2050	
Lafayette 230 kV Sub Breaker Repl with Ring Bus Phase 2	-	230	12/31/16			$450
TiptonWest –Kokomo Highland Park 230 kV line rebuild	14	230	6/1/2015	$400	$6500	$2200
Madison 138 kV Sub Breaker Repl Trans Relaying Upgrade		138	12/31/14	$1050	$2050	
Dresser – Wabash River new 138 kV line	10.5	138	6/1/16		$2900	$7200

*Excluding AFUDC

<u>Anticipated Project Milestones</u>

The completion of these projects, by their planned in-service dates and costs, are the project milestones. Individual project specific notes from the above tables are given as follows:
Note 1, 2, 3 – Project delayed to better coordinate outages in non-peak load windows and to ensure sufficient labor resources involved in four substation voltage conversions.
Note 4 – Wind developer requested project delay due to their internal scheduling.
Note 5 – Cost revised to reflect large power transformer early delivery.
Note 6 – Completion early due to favorable construction conditions and to reduce associated outage times affecting reliability of large municipal load
Note 7 – Assumed partial line switching costs for operational flexibility of ring bus

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The Duke Energy Indiana
2013 Integrated Resource Plan

November 1, 2013

Appendix H:
Cross-Reference to Proposed Rule

Appendix H: Cross-Reference to Proposed Rule

170 IAC 4-7 (Proposed 10/4/12) **Regulatory Requirement**	**Location in Duke Energy Indiana 2013 IRP Document**
Section 0.1 -Applicability	No Reponse Required
Section 1 - Definitions	No Reponse Required
Section 2 - Effects of filing integrated resource planning	No Reponse Required
Section 2.1 - Public Advisory Process	Chapter 3, Section E; Addendum
Section 2.2 - Contemporary Issues Tech Conf	No Reponse Required
Section 3 -Waiver or Variance Requests	No Reponse Required
Section 4 - Methodology and documentation	
(a) IRP Summary Document	Appendix I
(b)(1) inputs, methods, definitions	Chapter 3, Sections B & E; Chapter 4, Sections E & F; Chapter 5, Section F; Chapter 6, Section F; Chapter 8, Section B; Appendix A
(b)(2) forecast datasets	Chapter 3, Section D; Appendix B
(b)(3) consumption patterns	Chapter 3, Section D; Appendix B
(b)(4) customer surveys	Chapter 3, Sections D & E; Appendix B
(b)(5) customer self-generation	Chapter 3, Section C; Chapter 5, Sections C, D & E
(b)(11) contemporary methods	Chapter 3, Sections B & E; Chapter 4, Sections E & F; Chapter 5, Section D & F; Chapter 6, Section F, G; Chapter 8, Section B; Appendix A & G
(b)(6) alternative forecast scenarios	Chapter 2, Section B; Chapter 3, Section F; Chapter 4, Section D; Chapter 8, Section B
(b)(7) fuel inventory and procurement	Chapter 5, Section B
(b)(8) SO_2 emissions allowances	Chapter 6, Sections G & H
(b)(9) expansion planning criteria	Chapter 1, Section A; Chapter 2, Sections B, C & D
(b)(10)(A) power flow study	Appendix G
(b)(10)(B) dynamic stability study	Appendix G
(b)(10)(C) transmission reliability criteria	Appendix G
(b)(12) avoided cost calculation	Chapter 8, Section B; Appendix D
(b)(13) system actual demand	Appendix B
(b)(14) public advisory process	Chapter 3, Section E; Addendum
Section 5 - Energy and demand forecasts	
(a)(1) analysis of load shapes	Chapter 3, Section B; Appendix B
(a)(2) disaggregated load shapes	Appendix B
(a)(3) disaggregated data & forecasts	Appendix B
(a)(4) energy and demand levels	Chapter 3, Section F; Appendix B
(a)(5) weather normilization methods	Chapter 3, Sections B & E; Appendix B
(a)(6) energy and demand forecasts	Chapter 3, Section F; Appendix B
(a)(7) forecast performance	Appendix B
(a)(8) end-use forecast methodology	Chapter 3, Section E, part (2); Appendix B
(a)(9) load shape data directions	No response required
(b) alternative peak/energy forecasts	Chapter 3, Section F

(Appendix H Index continued)	
Regulatory Requirement	**Location in Duke Energy Indiana 2013 IRP Document**
Section 6 - Resource assessment	
(a)(1) net dependable capacity	Chapter 5, Figure 5-A; Appendix F
(a)(2) expected capacity changes	Chapter 1, Section A; Chapter 5, Section B; Chapter 8, Section B
(a)(3) fuel price forecast	Chapter 1, Section A; Chapter 5, Section B; Chapter 8, Section B
(a)(4) significant environmental effects	Chapter 1, Section A; Chapter 2, Section B; Chapter 5, Section B; Chapter 6, Sections F, G & H; Appendix E, Section B
(a)(5) transmission system analysis	Appendix G
(a)(6) demand-side programs	Chapter 4, All Sections; Appendix C; Appendix E, Section C
(b)(1) DSM program description	Chapter 4, All Sections; Appendix C; Appendix E, Section C
(b)(2) DSM avoided cost projections	Appendix C; Appendix E, Section C
(b)(3) DSM customer class affected	Chapter 4, Sections D & E; Appendix E, Section C
(b)(4) DSM impact projections	Chapter 1, Section A; Chapter 4, Sections D & E
(b)(5) DSM program cost projections	Appendix E, Section C
(b)(6) DSM energy/demand savings	Chapter 1, Section A; Chapter 4, Section E; Appendix C
(b)(7) DSM program penetration	Chapter 4, Section E; Appendix C
(b)(8) DSM impact on systems	Chapter 4, Section E; Appendix C
(c)(1) supply-side resource description	Chapter 5, Sections E, F & J; Chapter 8, Section B; Appendix A; Appendix E
(c)(2) utility coordinated cost reduction	Chapter 5, Section F
(d)(1) transmission expansion	Appendix G
(d)(2) transmission expansion costs	Appendix G
(d)(3) power transfer	Appendix G
(d)(4) RTO planning and implementation	Chapter 2, Section C; Chapter 5, Section D
Section 7 - Selection of future resources	
(a) resource alternative screening	Chapter 4, Sections F & G; Chapter 5, Section F; Chapter 8, Section B; Appendix A; Appendix C
(a)(1) environmental effects	Chapter 1, Section A; Chapter 2, Section C; Chapter 6; Appendix E, Section B
(a)(2) environmental regulation	Chapter 1, Section A; Chapter 2, Section C; Chapter 6; Appendix E, Section B
(b) DSM tests	Chapter 4, Section F; Appendix C
(c) life cycle NPV impacts	Chapter 8, Section B; Appendix D
(d)(1) cost/benefit components	Chapter 5, Section F; Chapter 8, Section B; Appendix A; Appendix C
(d)(2) cost/benefit equation	Chapter 5, Section F; Chapter 8, Section B; Appendix A; Appendix C
(e) DSM test exception	No response required
(f) load build directions	No response required
Section 8 - Resource integration	
(a) candidate resource portfolios process	Chapter 8
(b)(1) resource plan description	Chapter 1, Sections A & B; Chapter 8, Section B
(b)(2) significant factors	Chapter 1, Sections A & B; Chapter 2; Chapter 6; Chapter 8, Section B
(b)(7)(D) PVRR of resource plan	Chapter 8, Section B; Appendix A
(b)(4) utilization of all resources	Chapter 4; Chapter 5, Sections B, C, E, F & H; Chapter 8, Section B; Appendix C; Appendix E
(b)(7)(B)(i) risk management	Chapter 1, Section A; Chapter 2, Section B; Chapter 6; Chapter 8, Section B
(b)(7)(D) supply-side selection economics	Chapter 5, Sections E & F; Chapter 8, Section B; Appendix A; Appendix E

(Appendix H Index continued)	
Regulatory Requirement	**Location in Duke Energy Indiana 2013 IRP Document**
(b)(5) DSM utilization	Chapter 3, Section C; Chapter 4, Section F; Chapter 5, Sections C & E
(b)(6) plan operating and capital costs	Chapter 8, Section B; Appendix D
(b)(6) average cost per kWh	Chapter 8, Section B; Appendix D
(b)(6) annual avoided cost	Appendix D
(b)(6)(D) plan resource financing	Appendix D; Appendix E
(b)(7)(A&B) regulation assumptions	Chapter 1, Section A; Chapter 2, Section C; Chapter 5, Section B; Chapter 6; Chapter 8, Section B
(b)(8)(A) demand sensitivity	Chapter 3, Section F; Chapter 8, Section B; Appendix B
(b)(8)(B) resource cost sensitivity	Chapter 5, Section F; Chapter 8, Section B
(b)(8)(C) regulatory compliance	Chapter 1, Section A; Chapter 2, Section B; Chapter 6; Chapter 8, Section B
(b)(8)(D) other factor sensitivities	Chapter 5, Section F; Chapter 8, Section B
Section 9 - Short term action plan	
(1)(A) description/objective	Appendix D, Sections A, B & C
(1)(B) progress measurement criteria	Appendix D, Sections A, B & C
(2) implementation schedule	Appendix D, Sections A, B & C
(3) plan budget	Appendix D, Sections A, B & C
(4) prior STIP vs actual	Appendix E