STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A STEP-IN OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF A FEDERAL MANDATE CERTIFICATE UNDER IND. CODE § 8-1-8.4-1; (4) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING DEFERRAL RELIEF; AND (6) APPROVAL OF A REVENUE DECOUPLING MECHANISM FOR CERTAIN CUSTOMER CLASSES	)	**CAUSE NO. 45253**

VERIFIED DIRECT TESTIMONY
OF
KEITH B. PIKE

On Behalf of Petitioner,
DUKE ENERGY INDIANA, LLC

Petitioner's Exhibit 15

July 2, 2019

DIRECT TESTIMONY OF KEITH B. PIKE
STRATEGIC ANALYTICS DIRECTOR - FHO
DUKE ENERGY CAROLINAS, LLC
ON BEHALF OF DUKE ENERGY INDIANA, LLC
BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Keith B. Pike, and my business address is 1000 East Main Street, Plainfield, Indiana.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Carolinas, LLC, a utility affiliate of Duke Energy Indiana LLC ("Duke Energy Indiana" or "Company") as Strategic Analytics Director – FHO, in the Analytical Engineering Group.

Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES AS STRATEGIC ANALYTICS DIRECTOR – FHO?

A. My primary responsibility is to develop and maintain analysis tools, models, and processes for the purpose of assessing Duke Energy's generation fleet. Working in coordination with other departments, such as Integrated Resource Planning, I may also utilize these tools to assist in the performance of economic analysis of existing and new generation facilities. I also support various other activities such as economic evaluations of general capital improvements for existing generating facilities; business development research and technical analysis; and business strategic and/or risk assessments as may be requested by management or counsel.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated *Suma Cum Laude* with a Bachelor of Science in Mechanical Engineering degree from Purdue University in 1998. Following graduation, I was employed as a performance engineer at the Cinergy Cayuga Generating Station. I moved to the Cinergy Analytical and Investment Engineering Group in 2003, where I focused on developing modeling tools for economic evaluation of generating unit investments for compliance with environmental regulations. I became a Professional Engineer registered in the State of Indiana in 2005. Through several mergers, I continued in my primary role in the Analytical Engineering Group, steadily progressing upward through the engineering title classifications; I earned the highest level, Consulting Engineer, in 2008. Starting in 2014, I served as the Director of Generation and Regulatory Strategy for Duke Energy Indiana, where I facilitated strategic assessments of the generation fleet, and coordinated with the Legal Department on regulatory filings pertaining to generation. I assumed my current title in August 2015, returning to my primary analytics role.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony will address the reasonably expected lives of Duke Energy Indiana's generating plants that are used by Duke Energy Indiana witness Mr. John Spanos for depreciation rate purposes, and how they are consistent with the 2018 Duke Energy Indiana Integrated Resource Plan ("IRP") preferred portfolio. I will also discuss the impact of potential future climate policy on Duke Energy Indiana's generating plants and how that relates to the reasonableness of the generating plant retirement dates as shown in the IRP preferred portfolio. In addition, my testimony will discuss how the implementation of the IRP preferred portfolio promotes a transition to enhanced generating fleet diversity and reduced risk exposure for Duke Energy Indiana customers.

Q. PLEASE DESCRIBE DUKE ENERGY INDIANA'S GENERATING STATIONS.

A. Duke Energy Indiana's electric generating properties consist of: (1) two syngas/natural gas-fired combustion turbines ("CT") and one steam turbine; (2) one solar-powered facility, located at NSA Crane; (3) steam capacity located at three stations comprised of 9 coal-fired generation units; (4) combined cycle capacity located at one station comprised of three natural gas-fired CTs and two steam turbine-generators; (5) a run-of-river hydroelectric generation facility comprised of three units; and (6) peaking capacity consisting of four oil-fired diesels and 24 natural gas-fired CTs, one of which has oil back-up.

II. REASONABLY EXPECTED LIVES OF GENERATING FACILITIES

Q. HAS DUKE ENERGY INDIANA CONDUCTED A THOROUGH ASSESSMENT OF THE EXPECTED LIVES OF ITS GENERATING ASSETS FOR THIS RATE CASE?

A. Yes, we have. Historically, the industry has typically used "in-service date plus X years" concepts for depreciation retirement date purposes. The economics in the past generally supported running the units "forever," and through rigorous design and construction, prudent maintenance, and environmental control retrofits, the lives of some of our assets have been prolonged. But, times are changing;

customer expectations are changing; and economics are changing. Indeed, our entire industry is changing, and we must adapt. As such, we must carefully evaluate the continued reasonableness of assuming our coal assets can run for decades longer than their original expected lives.

Q. HOW LONG SHOULD COAL-FIRED STEAM ELECTRIC GENERATING UNITS BE EXPECTED TO LAST?

A. Generally, most industrial heavy equipment like boilers and turbines are initially designed and constructed to standards supporting about 30 to 40 years of service life. However, as noted above, with appropriate ongoing routine maintenance and capital component replacement, expected lives have been prolonged – frequently 25 years or more beyond those originally expected lives. Generating unit life expectations have also been increased due to equipment retrofits for compliance with environmental regulations starting from the 1990s and up to today, including flue gas desulfurization ("FGD" or scrubber) for sulfur dioxide ("SO_2") removal, and selective catalytic reduction ("SCR") for nitrogen oxide ("NOx") reduction and mercury ("Hg") oxidation. Environmental upgrades have also occurred over time on the water and waste management side of the industry, including most recently dry flyash, dry bottom ash, and water management retrofits.

It's fair to say that the major components of generating units (boilers and turbines) should last as long as they are properly maintained, but everything does have an ultimate end date. Take environmental controls, for example. They are typically exposed to the elements operating outside; they operate in corrosive conditions; and they are critical to the lawful permitted operation of the generating units. As such, the life of the environmental controls can be as or more critical than the boilers and turbines to the life of the overall assets.

Q. WHAT FACTORS AFFECT THE EXPECTED LIFE OF A COAL-FIRED STEAM ELECTRIC GENERATING UNIT?

A. There are both technical factors and economic factors. Key technical factors include the initial robustness of the design and construction of the unit; what environmental controls are original versus what environmental control retrofits or replacements occur in the life of a unit; the operational duty of a unit; the type and quality of the coal burned; and how well maintained the unit is. For example, on a technical basis, units with heavy operational duty would be expected to have shorter life expectations. Also, units with older environmental controls may also generally have shorter life expectations.

Key economic factors include fuel costs and unit efficiency; incremental environmental regulations' investment requirements; the evolution of competing technologies providing lower cost capacity and energy options; and the evolution of the regional transmission operator market,[1] which provides potential short-term options for the management of energy and capacity needs. For example, on an economic basis, units with higher operating costs and/or units facing substantial investments or costs of environmental compliance will have shorter life expectations as new technology and market options compete against them.

[1] For Duke Energy Indiana, "MISO", the Midcontinent Independent System Operator, Inc.

Q. WHAT ARE THE INDUSTRY TRENDS WITH RESPECT TO THE LIFE OF COAL-FIRED STEAM ELECTRIC GENERATING UNITS?

A. As I have indicated already, an important recent trend in coal-fired generating unit life expectation is the consideration of the age of environmental controls. We are seeing relatively new units proposed for retirement primarily because their environmental controls are either original equipment or were early retrofits, and are at the end of their useful lives. Whereas older boilers and turbines with newer environmental control retrofits may have life left to give.

The other high-profile developments in the industry are climate change and carbon emission risk. While the technological challenges of SO_2, NOx, and Hg emissions compliance are pretty much behind us, reducing carbon emissions represents a whole other level of complexity. There are no proven cost-effective retrofit control technologies like SCRs and FGDs for carbon. In addition, there is no such thing as "low carbon" coal (in reference to low sulfur coal that has been relied upon by units without environmental controls to reduce emissions for SO_2 compliance). Notwithstanding the ever-changing legislative direction from policymakers, stakeholder and public sentiment largely support the greening of our country's energy production, and new lower-carbon technologies are beginning to compete with coal in many regions even in the absence of an economic indicator (such as a tax on carbon emissions). With the combination of these factors, the industry is moving toward managed, staged retirement of coal units sooner rather than later, as a means to manage the carbon footprint risk and to reflect changing economic conditions.

Q. HOW LONG SHOULD GAS-FIRED COMBUSTION TURBINES BE EXPECTED TO LAST?

A. The life of asset concepts for combustion turbines are similar to those of coal units, but CTs generally have less environmental exposure. A life expectation of 40 years is fairly typical for new CTs. Generally, these machines should run to failure, or otherwise until displaced by better technologies providing intermediate and peaking services to the grid (such as combined cycle duct-firing, or perhaps, one day, such as batteries).

Q. WHAT FACTORS AFFECT THE EXPECTED LIFE OF A COMBUSTION TURBINE ELECTRIC GENERATING UNIT?

A. The primary factor is the operational duty of the unit. Units that are heavily cycled will generally have a shorter life expectation as the components of the engine are consumed more quickly. Similarly, units that run at higher capacity factor will consume component life more quickly, as peaking type units were not generally designed or intended for intermediate or base load operation.

Q. WHAT ARE THE INDUSTRY TRENDS WITH RESPECT TO THE LIFE OF COMBUSTION TURBINE ELECTRIC GENERATING UNITS?

A. Recently, the main trend has been that persistently low natural gas prices are driving higher numbers of startups and more run time on peakers, especially on the most efficient unit types. We are seeing this predominantly at our Henry County and Madison CTs. The Company’s Noblesville Combined Cycle Station was not envisioned to operate at base load, but with low natural gas prices, has been running at very high capacity factors recently. The system impact of intermittent renewables may also contribute to increased operational duty and reduced lifespan of CTs as the CTs are called upon more often to manage swings in renewables' output for grid stability.

Q. PLEASE DISCUSS THE LIFE EXPECTATIONS FOR OTHER TYPES OF ELECTRIC GENERATING UNITS, SUCH AS INTERNAL COMBUSTION, HYDRO, AND SOLAR UNITS.

A. For most older internal combustion diesel engines, classically referred to as black start engines, their lives generally follow the life of other units they are supporting on the site (such as the Cayuga diesels supporting the Cayuga steam units). So long as environmental upgrades were installed or other operational limitations imposed to comply with recent environmental regulations, these units are typically reliable to operate through the life of the base plant.

The life of hydro generation assets can vary widely, with some already over one hundred years old. For depreciation rate purposes, these units typically abide to the most recent Federal Energy Regulatory Commission ("FERC") operating license expiration date. Duke Energy Indiana's Markland Hydro Station has recently updated its FERC operating license and, with the upgrades currently underway, intends to operate throughout the updated FERC license (another 40+ years). Lastly, solar assets are relatively new to the Duke Energy Indiana generating fleet. We are currently following industry norms, generally at 25 to 30 years of expected life.

Q. PLEASE DISCUSS THE CURRENT RANGE OF EXPECTED LIVES FOR COAL-FIRED STEAM AND CT ELECTRIC GENERATING UNITS SEEN

IN THE INDUSTRY.

A. Table 1 below summarizes recently proposed, approved, or executed retirement[2] dates for Duke Energy Indiana's peer investor owned utilities ("IOUs") in the state. Generally, coal-fired unit service lives are being dramatically reduced by our peers, due to many of the factors I have discussed. Across our peer utilities, the average of proposed or recently executed retirements for coal units has been reduced from about 59 years of life to about 51 years of life, with the earliest retirement at 33 years of life, and the latest at 75 years. Coal units with the oldest environmental controls are being retired at a significantly accelerated pace, even though they are often the units with the youngest boilers and turbines. This is typically because these newest units were built with original or early retrofit environmental controls, as opposed to being retrofitted more recently with newer more efficient technologies. Take Vectren, for example, which has proposed to retire AB Brown Units 1-2, with original 1979 and 1986 vintage scrubbers, at 44 and 37 years of life respectively. Similarly, NIPSCO has already retired Bailly Units 7-8, which had early retrofit scrubbers in 1991, at 56 and 50 years of life respectively. NIPSCO is similarly proposing to retire the coal units at Schahfer Station, with boilers and turbines younger than 50 years. These units have varying vintages of scrubbers.

[2] Retirement in this general context is intended to represent the end of coal-fired service to customers for coal units. Across the various units in the table, that includes actual unit retirements, exiting of joint ownership or lease agreements, and gas conversion of coal units.

For CTs, most units of newer vintage have original proposed lives of 40 years. The CT unit types have experienced a similar general reduction in overall average life expectations with time, decreasing from about 50 years to 43 years.

Table 1: Indiana Peer IOU Generating Unit Retirement Dates

							Most Recent[6]		First Prior[6]	
Utility	**Station**	**Unit**	**Type**	**Capacity MW**	**In Service**	**Core Emission Controls[5] (SO2; NOx; Hg; PM)**	**Retirement Date**	**Asset Life years**	**Retirement Date**	**Asset Life years**
Vectren[1]							*2018 CCGT CPCN*		*2016 IRP*	
	AB Brown	1	Coal	245	1979	FGD(79); SCR(05); FF(04)	12/31/2023	44	2024	45
	AB Brown	2	Coal	245	1986	FGD(86); SCR(04)	12/31/2023	37	2024	38
	FB Culley	2	Coal	90	1966	FGD(94)	12/31/2023	57	2024	58
	FB Culley	3	Coal	270	1973	FGD(94); SCR(03); FF(06)	*Not Identified*	NI	*Not Identified*	NI
	Warrick (50%)	4	Coal	300	1970	FGD(09); SCR(04)	12/31/2023	53	2024	54
	AB Brown	3	CT	80	1991		*Not Identified*	NI	*Not Identified*	NI
	AB Brown	4	CT	80	2002		*Not Identified*	NI	*Not Identified*	NI
	BAGS	1	CT	50	1972		2/15/2018	46	2018	46
	BAGS	2	CT	65	1981		*Not Identified*	NI	2025	44
	Northeast	1	CT	10	1963		*Not Identified*	NI	2019	56
	Northeast	2	CT	10	1964		*Not Identified*	NI	2019	55
NIPSCO[2]							*2018 Rate Case*		*2015 Rate Case*	
	Bailly	7	Coal	160	1962	FGD(91); SCR(08)	5/31/2018	56	2022	60
	Bailly	8	Coal	320	1968	FGD(91); SCR(04)	5/31/2018	50	2022	54
	Michigan City	12	Coal	469	1974	FGD(15); SCR(03)	12/31/2028	54	2034	60
	R.M. Schahfer	14	Coal	431	1976	FGD(13); SCR(04)	12/31/2023	47	2036	60
	R.M. Schahfer	15	Coal	472	1979	FGD(15); SNCR(14)	12/31/2023	44	2039	60
	R.M. Schahfer	17	Coal	361	1983	FGD(83)	12/31/2023	40	2043	60
	R.M. Schahfer	18	Coal	361	1986	FGD(86)	12/31/2023	37	2046	60
	Bailly	10	CT	31	1968		12/31/2027	59	2019	51
	R.M. Schahfer	16A	CT	78	1979		5/31/2020	41	2020	41
	R.M. Schahfer	16B	CT	77	1979		5/31/2020	41	2020	41
IPL[3]							*2017 Rate Case*		*2016 IRP*	
	Petersburg	1	Coal	232	1967	FGD(96)	2042	75	2032	65
	Petersburg	2	Coal	435	1969	FGD(96); SCR(04); FF(15)	2042	73	2034	65
	Petersburg	3	Coal	540	1977	FGD(97); SCR(04)	2042	65	2042	65
	Petersburg	4	Coal	545	1985	FGD(85)	2042	57	2042	57
	Harding Street	5	Coal	100	1958	Gas Conversion(15)	2015	57	2031	73
	Harding Street	6	Coal	100	1961	Gas Conversion(15)	2015	54	2031	70
	Harding Street	7	Coal	430	1973	FGD(07); SCR(05); Gas Conv(15)	2015	42	2033	60
	Georgetown	1	CT	74	2000		2040	40	2050	50
	Georgetown	4	CT	75	2000		2040	40	2052	52
	Harding Street	4	CT	82	1994		2034	40	2044	50
	Harding Street	5	CT	82	1994		2034	40	2045	51
	Harding Street	6	CT	158	1994		2034	40	2052	58
I&M[4]							*2018 Rate Case*		*2015 IRP*	
	Rockport (85%)	1	Coal	1118	1984	DSI(13); SCR(17)	2028	44	Not Identified	NI
	Rockport (85%)	2	Coal	1105	1989	DSI(13); SCR(19)	2022	33	Not Identified	NI
	Clifty Creek (18%)	1-6	Coal	217 ea	1955	FGD(13); SCR(03)	Not Identified	NI	Not Identified	NI
	Kyger Creek (18%)	1-5	Coal	217 ea	1955	FGD(12); SCR(03)	Not Identified	NI	Not Identified	NI

Summary Statistics	**Coal**	**CT**	**Coal**	**CT**
Average	51.0	43.0	59.1	49.6
Minimum	33.0	40.0	38.0	41.0
Maximum	75.0	59.0	73.0	58.0

Notes

1 CCGT CPCN Cause No. 45052; Warrick 4 percentage represent ownership share of the unit, and its "retirement" represents exit of the ownership agreement

2 2018 Base Rate Case Cause No. 45159; 2015 Base Rate Case Cause No. 44688

3 2017 Base Rate Case Cause No. 45029; the 2015 date for Harding Street 5-7 represents secession of coal firing - actual depreciation retirement date is 2033

4 2018 Base Rate Case Cause No. 44976; Percentages represent ownership share of the units

5 FGD=Flue Gas Desulfurization; SCR=Selective Catalytic Reduction; FF=Fabric Filter; Numbers in parens are installation date as best interpreted from EPA NEEDSv5.13 or IRPs

6 "Not Identified" means that no specific retirement date could be interpreted from the data, or otherwise that the unit would continue to operate indefinitely. Units without retirement dates identified do not contribute to the average, maximum, or minimum statistics.

III. THE 2018 IRP PREFERRED PORTFOLIO

Q. PLEASE DESCRIBE THE COMPANY'S GENERATING UNIT RETIREMENT DATES REFLECTED IN THE DEPRECIATION STUDY FOR THIS RATE CASE.

A. Please see Table 2 below identifying the generating unit retirement dates in depreciation rates from the Company's last depreciation study (completed in 2011), along with the updated retirement dates Duke Energy Indiana has included in its new depreciation study filed in this proceeding. On average, the expected life in the last depreciation study of the coal units (excluding Edwardsport) was approximately 65 years, and of the simple cycle CTs was approximately 40 years. For Noblesville Combined Cycle, the life of the CTs was approximately 36 years, while the life used for the steam units was 89 years.

For the updated retirement dates in the depreciation study for this proceeding, the average life of the coal units decreases to approximately 58 years, ranging from 47 years to 64 years on individual units. The average life of the simple cycle CT units increases slightly to 41 years. The life of Noblesville Combined Cycle decreases slightly to 31 years for the CTs and 84 years for the steam units. Overall, the updates to the average lives, and the range of lives for individual units, are directionally consistent with industry trends. Further, these updates are consistent with the most recently proposed generating unit lives of Duke Energy Indiana's peer IOUs in the state.

Table 2: Generating Unit Existing and Updated Depreciation Retirement Dates

Unit	Type	In Service Date	Current Dates: Retire Date	Current Dates: Age at Retirement	Updated Dates: Retire Date	Updated Dates: Age at Retirement
Cayuga 1	Coal	10/4/1970	2035	65.2	5/31/2028	57.7
Cayuga 2	Coal	6/22/1972	2037	65.5	5/31/2028	55.9
Edwardsport IGCC	Syngas CC	6/7/2013	2045	32.6	5/31/2045	32.0
Gallagher 2	Coal	12/1/1958	2023	65.1	12/31/2022	64.1
Gallagher 4	Coal	3/1/1961	2026	65.8	12/31/2022	61.8
Gibson 1	Coal	5/3/1976	2041	65.7	5/31/2038	62.1
Gibson 2	Coal	4/16/1975	2040	65.7	5/31/2038	63.1
Gibson 3	Coal	3/28/1978	2043	65.8	5/31/2034	56.2
Gibson 4	Coal	3/27/1979	2044	65.8	5/31/2026	47.2
Gibson 5	Coal	10/1/1982	2047	65.2	5/31/2034	51.7
Noblesville ST 1-2	CC	1/1/1950	2038	89.0	5/31/2034	84.4
Noblesville CT3-5	CT	4/1/2003	2038	35.8	5/31/2034	31.2
Cayuga CT4	CT	6/29/1993	2033	40.5	5/31/2028	34.9
Cayuga Diesel 3a-d	IC	6/1/1972	2015	43.6	5/31/2028	56.0
Henry County CT1	CT	7/31/2001	2041	40.4	5/31/2038	36.8
Henry County CT2	CT	8/11/2001	2041	40.4	5/31/2038	36.8
Henry County CT3	CT	8/25/2001	2041	40.4	5/31/2038	36.8
Madison CT1	CT	5/29/2000	2040	40.6	5/31/2041	41.0
Madison CT2	CT	5/29/2000	2040	40.6	5/31/2041	41.0
Madison CT3	CT	5/29/2000	2040	40.6	5/31/2041	41.0
Madison CT4	CT	5/29/2000	2040	40.6	5/31/2041	41.0
Madison CT5	CT	6/15/2000	2040	40.5	5/31/2041	41.0
Madison CT6	CT	6/29/2000	2040	40.5	5/31/2041	40.9
Madison CT7	CT	6/15/2000	2040	40.5	5/31/2041	41.0
Madison CT8	CT	6/29/2000	2040	40.5	5/31/2041	40.9
Vermillion CT1	CT	6/1/2000	2040	40.6	5/31/2043	43.0
Vermillion CT2	CT	6/1/2000	2040	40.6	5/31/2043	43.0
Vermillion CT3	CT	6/1/2000	2040	40.6	5/31/2043	43.0
Vermillion CT4	CT	6/1/2000	2040	40.6	5/31/2043	43.0
Vermillion CT5	CT	6/1/2000	2040	40.6	5/31/2043	43.0
Vermillion CT6	CT	6/1/2000	2040	40.6	5/31/2043	43.0
Vermillion CT7	CT	6/1/2000	2040	40.6	5/31/2043	43.0
Vermillion CT8	CT	6/1/2000	2040	40.6	5/31/2043	43.0
Wheatland CT1	CT	6/1/2000	2040	40.6	5/31/2043	43.0
Wheatland CT2	CT	6/1/2000	2040	40.6	5/31/2043	43.0
Wheatland CT3	CT	6/1/2000	2040	40.6	5/31/2043	43.0
Wheatland CT4	CT	6/1/2000	2040	40.6	5/31/2043	43.0
Markland 1-3	Hydro	1/1/1967	2030	64.0	4/30/2061	94.3
Crane	Solar	1/31/2017			5/31/2047	30.3
Camp Atterbury	Solar+Stor	12/31/2019			5/31/2045	25.4

Average Lives

	Current Age at Retirement	Updated Age at Retirement
Coal	65.5	57.7
CT	40.4	40.8

Q. ARE THESE RETIREMENT DATES FROM THE NEW DEPRECIATION STUDY CONSISTENT WITH WHAT THE COMPANY SUBMITTED WITH ITS 2018 IRP?

A. Yes, they are. Duke Energy Indiana filed its 2018 IRP with the Indiana Utility Regulatory Commission ("Commission") on July 1, 2019.[3] Within the twenty-year planning horizon of the IRP, ranging from 2018 through 2037, the updated depreciation retirement dates are aligned with the Company's preferred portfolio.[4] Sections 4, 5, and 6 of the IRP describe in detail the assumptions, modeling, economic analysis, risk assessment, and ultimate logic leading to the selection of this preferred portfolio.

Q. PLEASE SUMMARIZE THE OVERALL RATIONALE FOR THE RETIREMENTS SHOWN IN THE IRP PREFERRED PORTFOLIO.

A. From a technical perspective, at the heart of the IRP preferred portfolio is an ordered and logical management of the end of life of the Company's generation assets, considering individual unit circumstances and reasonable practical constraints. The alignment of reasonably anticipated coincident retirements is employed, to the extent it facilitates practical replacement capacity portions, as opposed to applying the traditional simple "in-service-date plus X years" type of ordering. That concept likewise applies to considering the age of existing environmental controls, not just the boilers and turbines, as I discussed earlier.

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[3] The 2018 IRP was originally scheduled to be filed in November 2018, but was extended until July 1, 2019. Please find the 2018 IRP and stakeholder engagement materials located at https://www.duke-energy.com/home/products/in-2018-irp-stakeholder. Also, see *Administrative Notice Motion* in this proceeding for the 2018 IRP.
[4] Please see Section 1 of the 2018 IRP for a summary of the preferred portfolio.

Further, unless otherwise specified, all retirement dates shown in the preferred portfolio are set as "5/31/year" dates, corresponding to the existing MISO planning year construct, to avoid having to plan for part-year capacity replacement. As a result, where retirement dates may be referenced only with a year (like 2030), that is now intended to represent 5/31/2030 as opposed to 12/31/2030 or any other date.

Q. PLEASE SUMMARIZE THE RATIONALE FOR THE RETIREMENTS OF THE CAYUGA GENERATING UNITS AS SHOWN IN THE IRP PREFERRED PORTFOLIO.

A. For Cayuga Units 1-2, the prior depreciation study indicates a useful life of about 65 years, with split retirement dates at 2035 and 2037. Even with the last depreciation study being only about ten years old, these dates better mirror the state of the industry then, rather than now. In addition, the split retirement dates for the units are not practical and do not reflect how the station should actually be retired from a technical, economic and pragmatic standpoint.

It is not reasonable to assume that only one Cayuga unit can be retired; leaving only one unit operating at the site would result in a significant loss of economy of scale in operations and maintenance costs. Even further complicating the ultimate retirement of Cayuga Station is the provision of steam to the neighboring industrial customer. This steam service cannot be effectively maintained by only one steam unit, making the current two-year gap in retirement dates of the units impractical. Therefore, the new depreciation study sets the two

Cayuga steam units retirements in the same year – 2028, as reflected in the IRP preferred portfolio.

The Cayuga Unit 3a-d diesel internal combustion generator would also be retired coincidently with the steam units. The Cayuga diesel unit has been retrofitted for Reciprocating Internal Combustion Engine ("RICE") emission compliance,[5] allowing it to operate past what was its 2015 expected retirement date. That leaves the Cayuga simple cycle Unit CT4. The depreciation retirement date for Cayuga Unit CT4 in the prior depreciation study was 2033. It makes more sense to retire this smaller single gas-fired unit at the time the rest of the station retires. In addition, Cayuga Unit CT4 is an uncommon unit, with very few other units like it in service today. It is not unreasonable to anticipate waning manufacturer expert support and parts availability for maintenance of this unit, leading to a somewhat shorter than previously assumed life expectation.

Overall then, in terms of resource planning, the total Cayuga Station (Unit 1-4) block size is 1,085 MW. It would be ideal to replace the Cayuga steam units with at least two new units with steam technology on-site to continue reliable service of steam to the industrial customer, making it logical and reasonable to replace the entire Cayuga Station (including Units 1-4) with a new large scale natural gas combined cycle unit. This technology perpetuates the reliable industrial steam service with two (or more) CTs with heat recovery steam generators, and including a duct burner effectively replaces the equivalent

[5] As approved by the Commission in Cause No. 44765.

peaking capacity of the Cayuga diesel and Unit CT4. Cayuga Station is located approximately only ten miles from a large-scale interstate natural gas pipeline that would provide adequate fuel supply for this unit. The IRP preferred portfolio indicates the replacement of Cayuga Station with such a unit.

Q. ARE THERE OTHER BENEFITS OF THE UPDATED RETIREMENT STRATEGY FOR THE CAYUGA GENERATING UNITS?

A. Yes. Two key additional benefits of the Cayuga retirement and replacement strategy include the use of emissions netting credits of the retiring units for purposes of permitting the new units, as well as retaining and reusing the transmission interconnect service on-site at Cayuga Station. It is typical and ideal to locate new generation at retiring brownfield sites to realize these types of benefits. If new large-scale generating assets are not sited at Cayuga, then we may expect to have to implement some transmission system upgrades to manage the impact to the grid of the retirement of the facility.

Q. WHAT ARE THE RESULTING LIVES OF THE CAYUGA UNITS PER THE IRP PREFERRED PORTFOLIO?

A. The retirement date for Cayuga Units 1-4 in the IRP preferred portfolio and in the new depreciation study is 2028. This results in lives of 58 years for Cayuga Unit 1, 56 years for Cayuga Unit 2, 56 years for the Cayuga Diesel, and 35 years for Cayuga Unit CT4.

Q. DO YOU CONSIDER THE RESULTING USEFUL LIVES OF THE CAYUGA UNITS TO BE REASONABLE?

A. Yes. The resulting lives of the Cayuga coal Units 1-2 are in the mid-to-high end of the range of our peers. The life for Cayuga Unit CT4 is 35 years, rather than the 40 years expected for gas-fired CTs, but again maintenance support for this unit may be expected to wane, and alignment with the retirement of the other units on the Cayuga site is a practical solution.

Q. PLEASE SUMMARIZE THE RATIONALE FOR THE RETIREMENTS OF THE GIBSON GENERATING UNITS 3, 4, AND 5 AS SHOWN IN THE IRP PREFERRED PORTFOLIO.

A. For Gibson Units 3-5, the prior depreciation study indicates a useful life of about 66 years, with retirement dates of 2043, 2044, and 2047 respectively. Again, these average life expectations better reflect 2010 industry conditions than current day expectations.

Of critical importance in planning the retirement of these units is the age of their environmental controls. While the Gibson Unit 3 scrubber is relatively new, having been installed in 2006 (along with Gibson Units 1 and 2 in 2007), the Gibson Unit 4 scrubber was installed in 1995, and Gibson Unit 5's scrubber is original equipment from 1982. While both the Gibson 4 and 5 scrubbers have undergone mechanical refurbishment and upgrade work in the past,[6] the vast majority of all structural elements, including the stacks, are original. The accompanying reagent preparation and waste product fixation systems are also original. The higher sulfur dioxide emission rates from these units, along with

[6] As approved by the Commission in consolidated Cause Nos. 42622 and 42718.

their shorter stacks, could also expose them to more risk from potentially more stringent environmental regulations over time. Should the Company need to replace these scrubbers with new technology, the cost would be prohibitive. We therefore address the Gibson Units 4 and 5 retirements first, even though they have the newest boilers and turbines at the site. Complicating this, however, is the fact that Gibson Unit 5 is a jointly owned unit, which means that Duke Energy Indiana does not have sole decision-making authority over this unit. Therefore, very thoughtful planning discussions with the Joint Owners will be required to execute its retirement.

To effectively stage the retirements of the Gibson Units in a manageable way, along with beginning to better diversify the Duke Energy Indiana generation portfolio while minimizing cost, the IRP preferred portfolio shows Gibson Unit 4 retiring first, in 2026. This unit is then replaced by renewables, mostly solar with some wind in the preferred portfolio, helping to rapidly add diversification to the Duke Energy Indiana generating fleet. Retiring Gibson Unit 5 first would have provided only half of that amount of diversification benefit for customers, Duke Energy Indiana’s ownership share, while leaving the Joint Owners needing to replace their capacity shares.

Still, Gibson Unit 4’s scrubber (vintage 1995) is far superior to Gibson Unit 5’s scrubber (vintage 1982) in both condition and performance. It would be logical to consider utilizing Gibson Unit 4’s scrubber past the retirement of its boiler and turbine. Therefore, while we intend to retire the Gibson Unit 4 boiler and turbine first, we will keep the Unit 4 scrubber in operation and re-route the flue gas from Gibson Unit 5 into Gibson Unit 4's scrubber. This will allow the retirement of the Gibson Unit 5 scrubber in 2026, and ensure that Gibson Unit 5's boiler and turbine can continue to operate with a more efficient scrubber. From there, the IRP preferred portfolio depicts Gibson Units 3 and 5 (with Unit 5 operating through Unit 4's scrubber) continuing to operate until 2034.

Q. ARE THERE OTHER CONSIDERATIONS FOR PLANNING THE RETIREMENT OF THE GIBSON UNITS?

A. Yes. Gibson Station is the largest single generation facility in the Duke Energy fleet, and is also the largest facility in the State of Indiana. The raw size of the station requires thoughtful planning, with careful staging of the units' retirements to manage its replacement. It is difficult to conceptualize retiring the entire station at once. Additionally, unlike Cayuga, which is situated close to existing interstate natural gas pipelines, the Gibson Station site has very limited access to natural gas fuel. Gibson Station is not a good candidate location for large scale replacement natural gas-fired generation. Therefore, we anticipate having to make some transmission system upgrades as the unit retirements at Gibson Station progress. These transmission system upgrades would need to be performed prior to the retirement of the units, in coordination with MISO. These activities typically have a significant lead time to plan, permit and execute, mandating knowledge of the unit retirements well in advance. Since the status of the MISO queue changes frequently (such as forecasted retirements, new resources, and transmission projects), the actual transmission system work scope will not be known until the MISO "Attachment Y" retirement studies are performed closer to the anticipated unit retirement dates. We expect that staging the retirement of the Gibson units will help spread out this burden and facilitate management of the transmission system reliability.

Q. WHAT ARE THE RESULTING LIVES OF THE GIBSON UNITS 3, 4, AND 5 FROM THE IRP PREFERRED PORTFOLIO AND THE NEW DEPRECIATION STUDY?

A. The retirement dates for Gibson Units 4, 3 and 5 reflected in the IRP preferred portfolio are 2026, 2034, and 2034 respectively. This results in lives of 47 years for Gibson Unit 4, 56 years for Gibson Unit 3, and 52 years for Gibson Unit 5.

Q. DO YOU CONSIDER THE RESULTING USEFUL LIVES OF THESE GIBSON UNITS TO BE REASONABLE?

A. Yes, I do. The resulting lives of Gibson Units 3 and 5 are again right in the mid-to-high end of the range of our peers, and the life of Gibson Unit 5 has been increased by re-using Gibson Unit 4's scrubber. Further, for all the reasons I have discussed, the staging of the retirement of Gibson Station must be well managed in time. One unit must be the one to go first, and based on current conditions and known constraints, Gibson Unit 4 is that best candidate unit. That said, there may be technical advantages to retiring all of Gibson Unit 5 first (simply swapping the retirement order of Units 4 and 5), avoiding the complexity of a tie-in flue-gas duct to continue using the Unit 4 scrubber. While, as I discussed earlier, retiring Unit 5 first would reduce the amount of near-term diversification benefit for customers, if agreement on the retirement can be reached with the Gibson Unit 5 Joint Owners, it could be a reasonable option.

Q. PLEASE DESCRIBE THE NOBLESVILLE COMBINED CYCLE STATION.

A. Noblesville Station is a unique 3x2 repowered natural gas-fired combined cycle generation facility. Three combustion turbines with heat recovery steam generators were installed in 2003, providing incremental power output, and providing steam to feed two existing steam turbine generators at the site from 1950 still housed in the original building. These steam units were originally coal-fired, but the coal boilers were retired in 2003 when the repowering project went into service. Noblesville is an efficient well-operating plant, but the mix of equipment vintages presents a challenge to managing its eventual retirement.

Q. PLEASE SUMMARIZE THE RATIONALE FOR THE RETIREMENT OF THE NOBLESVILLE COMBINED CYCLE STATION AS SHOWN IN THE IRP PREFERRED PORTFOLIO.

A. For Noblesville Station, the retirement date of 2038 from the prior depreciation study resulted in lives of 36 years for the combustion turbines, and 89 years for the repowered steam turbines. Should the Company assume a general industry standard expectation of 40 years of life for CTs, the Noblesville steam turbines would be over 90 years old at end of their life. Ninety years is not a reasonable assumption for longevity of this equipment, especially considering that the station has been running at very strong capacity factors recently. Therefore, by reasonable necessity, the preferred portfolio has the CTs retiring at the same time as the steam turbines, with the age of the steam turbines driving the date. In terms of fit to the overall system retirement trajectory, the Noblesville Station retirement date of 2034, coincident with Gibson Units 3 and 5 retirements, results in a 31-year life for the CTs and an 84-year life for the steam turbines. The combined block size of Gibson Units 3 and 5, and Noblesville (1,204 MW including Duke Energy Indiana's ownership share of Unit 5) is a practical size for replacement considerations of base load generation assets.

Q. ARE THERE OTHER OPTIONS FOR MANAGING THE END OF LIFE OF THE VASTLY DIFFERENTLY COMPONENT AGES AT NOBLESVILLE?

A. Yes, there is one other realistic option that would be technically possible, but likely cost prohibitive. The station could be reconfigured for simple cycle operation of the combustion turbines upon the retirement of the steam turbine generators. Unfortunately, this would require significant modifications to the CT exhausts. The current stacks are not designed for the direct high temperature exhaust gas of the turbines, so the heat recovery steam generators would need to be promptly demolished to make way to install new exhaust stacks. Additionally, the fuel pre-heater would have to be replaced, as the current pre-heater is steam fed. The control system would also have to be reprogrammed. Conversely, however, as I discussed for Cayuga and Gibson, a tradeoff could be avoided (or at least deferred) transmission system upgrade costs.

Overall, simple cycle conversion of Noblesville is a technically feasible option, but would require a substantial capital investment and a long conversion outage (primarily for demolition and stack construction). Further, the remaining life of the converted units may only be another ten years after conversion, making it unlikely that this option would be economic. While this option may deserve due consideration as the Noblesville retirement date approaches, we believe it is most appropriate today to plan for coincident retirement of the entire facility as discussed above.

Q. WHAT IS THE RESULTING LIFE OF NOBLESVILLE PER THE IRP PREFERRED PORTFOLIO?

A. The retirement date for Noblesville Station in the IRP preferred portfolio is 2034. This results in lives of 31 years for the CTs, and 84 years for the steam units.

Q. DO YOU CONSIDER THE RESULTING USEFUL LIVES OF THE COMPONENTS OF NOBLESVILLE TO BE REASONABLE?

A. I do, but I remain concerned that 84 years of age on the steam units is still a stretch from a technical standpoint. As discussed above, the option of simple cycle conversion of the station could extend the life of the CTs, but at a cost. That option can be considered down the road, as 2034 approaches.

Q. PLEASE SUMMARIZE THE RATIONALE FOR THE RETIREMENTS OF GIBSON UNITS 1 AND 2 IN THE DEPRECIATION STUDY.

A. The new depreciation study shows a retirement date for Gibson Units 1-2 of 2038, giving those units the longest life expectation of any of the scrubbed units at 62 years and 63 years respectively. These retirements remain outside the window of the IRP preferred portfolio, and hence have not been explicitly analyzed. The prior depreciation study showed these units having a useful life expectation of about 66 years. With the exception of three of IPL’s Petersburg units, and the OVEC units (Clifty Creek and Kyger Creek, which have a complicated ownership structure), Gibson Units 1-2 would achieve the longest life of any of the other remaining scrubbed coal units with retirement dates identified among our peer IOUs, as shown in Table 1.

While the overall site economy of scale for operating cost efficiency is expected to decrease as each of Gibson Units 3-5 retire, Gibson Units 1-2 share many common systems that will enable ongoing economic operation as a two-unit site. Gibson Units 1-2 are essentially housed in a completely separate building from Units 3-5; management and engineering offices, the maintenance shop, as well as the Unit 1-2 control room are all located in this separate building. This separation will enable efficient management of the site while Units 3-5 may be undergoing decommissioning and demolition activities, likely starting with Unit 5 and working inward. Gibson Units 1-2 also share many operating systems, including the scrubber reactant preparation, and waste handling and fixation systems, as well as a common stack. The Gibson Unit 1-2 scrubbers are the newest installed at the site, in-service in 2007. The Gibson Unit 1-2 precipitators were also built anew in the 1990s; the precipitators were built very large, with the latest technology, operated initially with less corrosive lower sulfur coal, and continue to be in excellent mechanical and electrical condition today. So once again, notwithstanding that Gibson Units 1-2 have the oldest boilers and turbines at the site, the age, condition, and performance of their environmental controls, along with other inherent operating efficiencies, dictate they be retired last and together.

Q. DO YOU CONSIDER THE RESULTING USEFUL LIVES OF GIBSON UNITS 1 AND 2 TO BE REASONABLE?

A. Yes. As discussed in detail in Section 5 of the IRP, across the range of future scenarios and generation portfolios analyzed, the analysis tended to maintain operation of at least a couple of coal units past the twenty-year planning horizon, even in scenarios more adverse to coal. Said differently, not all of the coal units were economically retired in the twenty-year period. Therefore, it is reasonable to see some longer life coal units remain in the fleet, and Gibson Units 1-2 best fit that bill.

Q. PLEASE DISCUSS THE SELECTION OF OTHER RETIREMENT DATES THAT ARE BEYOND THE TWENTY-YEAR IRP PLANNING HORIZON.

A. Edwardsport IGCC, most of the simple cycle CTs, Markland Hydro, and the new solar facilities all have retirement dates in the new depreciation study beyond the IRP twenty-year planning horizon. Being the newest large scale generating unit in the fleet, the retirement date for Edwardsport IGCC was not changed (except for minor realignment to the MISO planning year) from the date previously approved in Cause No. 43114 IGCC-8. Similarly, the expected lives for Crane Solar and Camp Atterbury Microgrid[7] are as previously approved in Cause Nos. 44734 and 45002, respectively. For Markland Hydro, the retirement date was extended to match the new FERC license expiration date.[8] The Markland units

[7] Camp Atterbury Microgrid is expected to be in service by the end of 2019.
[8] https://www.ferc.gov/industries/hydropower/gen-info/licensing/active-licenses.xls?csrt=266297369005558339

are in the process of receiving major overhauls to support the extended operational life.

Next, Duke Energy Indiana has about 1,500 MW of simple cycle CT units at four sites (Henry County, Madison, Vermillion, and Wheatland) that were all built around the same time (2000-2001). However, these units did not enter the Duke Energy Indiana system simultaneously, affording customers a ramp into their costs. Using a simple common industry asset life, these units would all retire at essentially the same time. While not analyzed as part of the 2018 IRP given its shorter planning horizon, this would likely necessitate capacity replacement in one large block. Again, to manage the overall staging of retirements and replacements, we think it is reasonable to consider injecting some separation into these retirement dates, even if some units would retire a little earlier than the industry average, while some units retire a little later.

The type of unit and operational duty of the units can be used as good measures of which may run longer or shorter. All of these units are frame design units (meaning they were explicitly designed for the purpose of stationary power production) except for Henry County, which are aero-derivative units (meaning their design was derived from jet engines). Aero-derivative units are generally less robust than frame design units. Further, the following table shows the average number of historical starts per unit, per year, which is a good indication of unit duty for a simple cycle CT.

Table 3: Simple Cycle CT Historic Operational Duty

	Unit Average Starts per Year		
	Over Life	Past 5 Years	Station MW
Henry County	148	181	129
Madison	97	124	566
Wheatland	34	45	355
Vermillion	34	44	450

As can be seen, Henry County and Madison have been operated much more heavily than Vermillion and Wheatland. With its heavy operation and aero-derivative design, it is reasonable for Henry County to be assumed to have the shortest life expectation, selected at 37 years (a reduction from the 40 years in the prior depreciation study), and retire in 2038. Combined with the Gibson Unit 1-2 retirements in that year, the retirement block size is 1,389 MW. This again is a manageable size for potential replacement with a natural gas combined cycle unit with duct burning, providing both the base load and intermediate/peaking capabilities. As the 2018 IRP does not opine on the replacement of Gibson Units 1-2 or Henry County, other types of replacement capacity technologies could also certainly be competitive by then. We are not making any replacement technology recommendations for these retirements at this time.

Lastly, Madison is assumed to retire next at 41 years of life, followed by a slightly longer life for Vermillion and Wheatland at 43 years. From a group depreciation rate perspective, the average of the CT facilities with separated retirement dates (including Cayuga Unit CT4) is not significantly different from if the retirement dates were not separated. However, from a resource planning perspective, this logical staging of retirements provides reasonably manageable blocks of peaking capacity for replacement.

IV. FUTURE ENVIRONMENTAL RISKS

Q. WHAT ENVIRONMENTAL RISKS ARE MOST HEAVILY INFLUENCING DUKE ENERGY INDIANA'S PLAN FOR THE FUTURE?

A. The climate change issue in general, and carbon dioxide (CO_2) emissions from our coal generating fleet in particular, weigh heavy on Duke Energy's future planning. This is being driven primarily based on three evolving sets of circumstances. First is the likelihood that an economic signal (such as a tax or other price structure) will be imposed at some point on CO_2 emissions through federal or other policies. Second is the fact that customer, investor, and other stakeholder expectations have been increasing that Duke Energy and our peer utilities should be working to significantly reduce our CO_2 emissions, sooner rather than later, whether there is a governing federal (or other) policy or not. And third is Duke Energy's own corporate commitment to reduce its overall carbon footprint.[9] These important signposts are prompting us to review our assumptions about how long our existing coal-fired assets, in particular, can reasonably remain in operation.

Q. WHAT MECHANISMS ARE IN PROCESS TODAY THAT COULD RESULT IN THE REGULATION OF CO_2 EMISSIONS?

A. In June of 2019, the U.S. Environmental Protection Agency ("EPA") finalized the Affordable Clean Energy ("ACE") rule. This rule, proposed in August 2018, seeks to reduce CO_2 emissions from existing coal-fired steam electric generating

[9] See the 2018 Duke Energy Sustainability Report at https://sustainabilityreport.duke-energy.com/

units. It requires states to develop implementation plans establishing CO_2 emission rate limits (in pounds of CO_2 per megawatt-hour) at the unit level. The CO_2 emission rate limits will be based on generation efficiency improvements that can be adopted "inside the fence" at existing power plants. The ACE rule lists six individual "candidate technologies" for efficiency improvements that states should consider for application at individual generating units.[10] EPA finalized the ACE rule on June 19, 2019. Once published in the Federal Register, States will have three years to develop implementation plans. Compliance will be required generally within two years after state plan approval by EPA, or roughly in the 2024-2025 timeframe. The ACE rule replaces the Clean Power Plan ("CPP").[11]

Q. WHAT IMPACT WILL THE ACE RULE HAVE ON THE OPERATION OF DUKE ENERGY INDIANA'S GENERATING UNITS?

A. While the requirements won't be known until the state implementation plan is developed, Duke Energy Indiana's Gibson and Cayuga coal-fired units generally have already installed the most major of the candidate technologies identified in

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[10] In addition to improved operating and maintenance practices, the six "candidate technologies" EPA lists in the ACE rule are neural network/intelligent sootblowers; boiler feed pump upgrades; air heater and duct leakage control; variable frequency drives; steam turbine blade path upgrades; and redesign/replace economizer.

[11] The Clean Power Plan was a regulation promulgated under the Obama administration requiring the reduction of CO_2 emissions from existing electric generating units through three main "building block" actions: Efficiency improvement of generating units; re-dispatching to reduce the output of coal-fired generating units in favor of gas-fired generating units; and installation of new renewable energy resources. It required states to impose either rate-based limits (lbs. CO_2/MWHR) or mass caps (tons of CO_2 per year) on individual power plants. If states chose mass caps, those would manifest into allowance prices like those in cap-and-trade based programs (such as SO_2 and NOx). The CPP was stayed in February 2016 in a rare action by the U.S. Supreme Court and never took effect.

the ACE rule. That includes steam turbine blade path upgrades and variable frequency drives on induced draft fans. Gibson Station also has operating neural networks on its units. The economizers on the Gibson and Cayuga units have also already been replaced; they have been optimized for heat recovery while balancing the required gas temperatures for proper operation of SCR catalyst for NOx removal. The remaining candidate technologies are generally smaller in scope and cost to implement. Therefore, the overall impact of the ACE rule on the Duke Energy Indiana generating fleet will likely be relatively small from an investment perspective, although we will have to learn how to operate under the new CO_2 emission rate limits. Also, Gallagher will be retired before the implementation plans would take effect, and the ACE rule is not applicable to Edwardsport IGCC.

Q. ARE THERE OTHER COURSES OF ACTION THAT COULD RESULT IN THE REGULATION OF CO_2 EMISSIONS?

A. Yes. Besides the EPA, Congress certainly has the authority to enact new legislation that would require CO_2 emission reductions. There has been a long history of such attempts, but successful legislation has been elusive. Over the past ten years, numerous federal policy proposals have been (and continue to be) advanced that would place a price on CO_2 emissions from the power sector, or across the economy in general. A prominent past proposal is the Waxman-Markey cap-and-trade bill from 2009 that would have resulted in estimated 2015 market prices for CO_2 allowances of between $10-$40/ton.[12] More recently, a prominent group of former federal officials is supporting the Climate Leadership Council's ("CLC") proposal that would impose a CO_2 price starting at $40/ton.[13] Yet another proposal, introduced in the 116th Congress (H.R. 763 sponsored by Rep. Deutch (D-FL)), would impose a CO_2 "fee" starting at $15/ton in 2019, escalating at $10/ton per year. Lastly, again recently, is the "Green New Deal" proposal, being circulated by some Democrats, that would seek to completely decarbonize the power industry by 2030. Overall, there is a wide range of structure, timing, and degree of potential impact of such CO_2 regulation proposals. Of course, it is impossible to predict what if any legislation or regulation may come to fruition in this or any future Congress or administration. However, it is clear that acting now to reduce carbon dioxide emissions on our system will better prepare the Company for any legislation or rules that are ultimately enacted, and reduce the cost of compliance in the long term.

Q. IN THE ABSENCE OF SPECIFIC POLICY DIRECTION, HOW IS DUKE ENERGY DEVELOPING ITS STRATEGY AROUND CO_2 EMISSIONS?

A. First and foremost, Duke Energy is listening. Duke Energy's customers, investors, and other stakeholders continue to press the Company for carbon emission reductions, and to provide more options for low- or zero-carbon energy.

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[12] See, for example, https://www.heritage.org/government-regulation/report/the-economic-impact-waxman-markey; and http://eea.epri.com/pdf/costs-of-climate-policy/405680__Understanding_Waxman-Markey_Webcast_Final.pdf, showing allowance prices starting in 2015 at approximately $10-$40/ton.
[13] See https://www.clcouncil.org/. The CLC proposal does not specify at this point a starting date or escalation rate.

For example, the Company is experiencing substantial pressure from investors (from both equity and debt holders) to reduce carbon emissions exposure.[14] This issue is even appearing in reports from credit rating firms.[15] Failure to take meaningful action could hamper the Company's access to capital, and/or increase the Company's cost of capital thereby raising customer rates. In addition, numerous industrial and commercial companies have committed to procure 100% renewable energy[16]; many of these companies are customers of Duke Energy Indiana. Further, many utility company peers of Duke Energy Indiana have committed to significant CO_2 emission reductions. That includes American Electric Power, which has committed to reduce its CO_2 emissions 60% below 2000 levels by 2030, and 80% below 2000 levels by 2050. And in Indiana, NIPSCO plans to reduce CO_2 emissions 90% by 2030.

Q. WHAT COMMITMENT HAS DUKE ENERGY MADE TO REDUCE ITS CARBON FOOTPRINT?

A. As detailed in Duke Energy's 2017 Climate Report to Shareholders, the Corporation, as a whole, has reduced its CO_2 emissions by 31 percent since 2005, and has set its sights on even greater progress.[17] In 2017, Duke Energy

[14] For example, the Climate Action 100, a group of more than 300 investors with more than $33 trillion in assets under management, has listed Duke Energy as among its list of 100 focus companies. The group's purpose is "to ensure the world's largest corporate greenhouse gas emitters take necessary action on climate change." The group goes on to state that it therefore supports "the Paris agreement and the need for the world to transition to a lower carbon economy consistent with a goal of keeping the increase in global average temperature to well below 2° Celsius above pre-industrial levels." (https://climateaction100.wordpress.com)

[15] See, for example, Moody's Investors Service, "Climate-related disclosures by four major utilities vary in both depth and scope," December 4, 2018.

[16] http://there100.org/companies

[17] https://www.duke-energy.com/_/media/pdfs/our-company/shareholder-climate-report.pdf

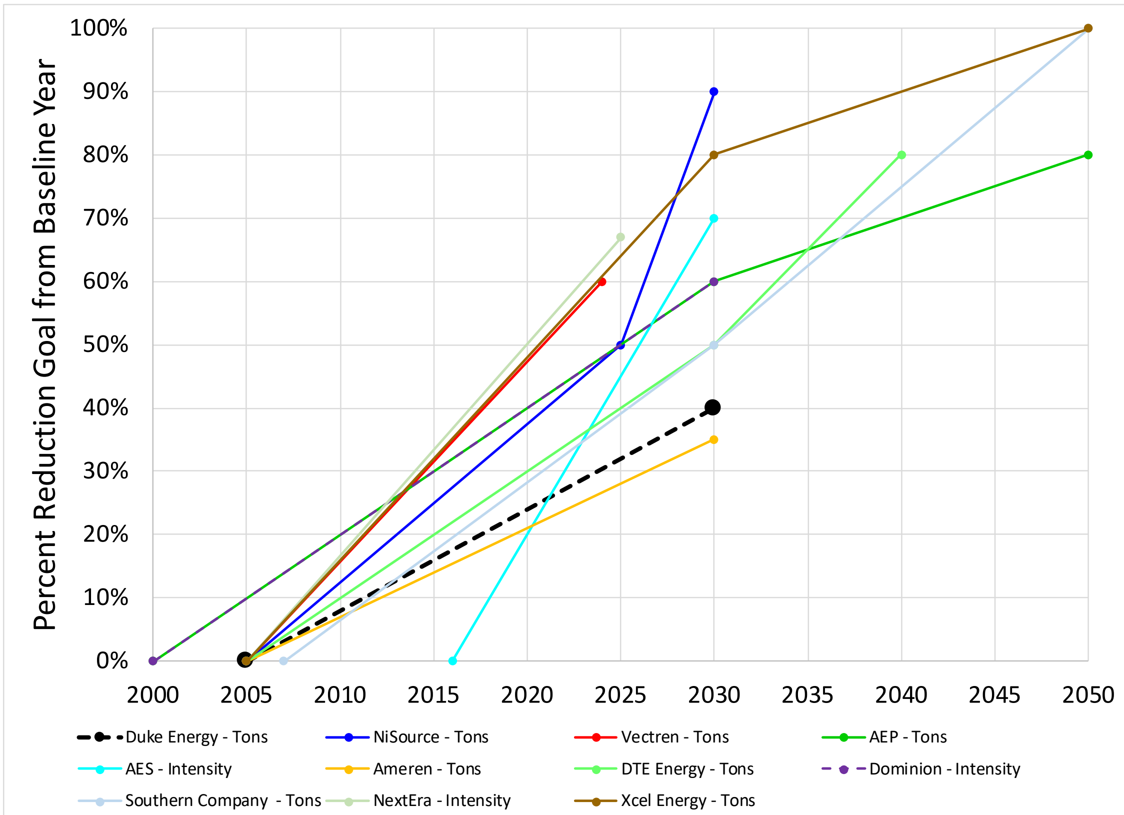
established a goal to reduce total CO_2 emissions by 40 percent from 2005 levels by 2030. But that doesn't mean we intend to stop there. Beyond 2030, the Company's long-term strategy will continue to drive carbon out of our system.

Q. HOW DOES DUKE ENERGY'S CARBON REDUCTION GOAL COMPARE TO OTHERS IN THE INDUSTRY?

A. Figure 1 below shows a compilation of CO_2 emission reduction goals over time for several Duke Energy regional peer utilities. There is a broad mix of baseline years and goal structures represented, including both mass emission and emission rate (intensity) metrics. Most of Duke Energy's peer utilities' carbon reduction goals are more aggressive than ours. However, many of the most aggressive goals have only been announced in the last twelve to eighteen months, whereas Duke Energy was among the early movers in setting a commitment. We continue to monitor the conditions in the industry, and will adjust our future carbon emission expectations as able at the appropriate time.

See Figure 1 on next page.

Figure 1: Peer Utility Carbon Reduction Goals



Q. WHAT ACTIONS BY DUKE ENERGY INDIANA SUPPORT THE COMPANY'S ATTAINMENT OF ITS 2030 GOAL?

A. When it was established in 2017, Duke Energy Indiana's contributions to achieving this goal were to come predominantly from generating unit retirements that had already occurred. Relative to other Duke Energy jurisdictions that have baseload nuclear and/or substantial natural gas combined cycle generation, Duke Energy Indiana continues to be relatively coal-heavy, and hence carbon-intensive, in delivering energy. This lack of energy diversity in Indiana is one notable risk that the 2018 IRP preferred portfolio seeks to mitigate. The Cayuga Station and Gibson Unit 4 retirements as shown in the preferred portfolio will further support the Company in meeting and exceeding the 2030 goal, helping to better position us more in line with our peers on energy diversity and managing carbon risk.

Q. IN THE ABSENCE OF POLICY WITH A DIRECT ECONOMIC IMPACT TO CUSTOMERS (SUCH AS A CARBON PRICE), HOW DOES SHIFTING DUKE ENERGY INDIANA'S GENERATION OVER TIME TO A MORE DIVERSE ENERGY MIX PROVIDE CUSTOMER VALUE?

A. Duke Energy Indiana's 2018 IRP preferred portfolio is a thoughtful first step towards meeting the changing expectations of our stakeholders, and reducing our CO_2 emissions in the state. Duke Energy Indiana believes it would be risky for us and our customers to simply wait for carbon policy to happen. Making moderate shifts in the expected remaining lives of our coal-fired assets is a reasonable action to take now, while we continue to monitor the changing industry landscape and impacts of market forces. With this first step, Duke Energy Indiana can take these next few years to position itself to make decisions on its assets in a measured way that mitigates risks to customers. Doing nothing, however, would be a risky option. The longer we wait, the more likely the potential is that Duke Energy Indiana could need to implement future policy with more extreme immediate impacts, rather than ramping in those requirements in a more manageable fashion.

Duke Energy Indiana has an obligation to our customers to try its best to react to the changing industry landscape in a thoughtful, moderate, and executable fashion, in order to transition into a lower carbon footprint in Indiana in a way that manages coal unit retirements, replacements, grid reliability, and cost impacts to customers. Mitigating the risks to our customers of these realities makes sense, is a reasonable and prudent course of action, and will help the Company continue to deliver safe, reliable, cost-effective and increasingly clean energy to customers, while managing our climate risk exposure and balancing customer rate impacts.

V. CONCLUSION

Q. DID YOU WORK WITH BOTH MR. SPANOS AND THE IRP TEAM ON THE GENERATING UNIT RETIREMENT DATES IN THE DEPRECIATION STUDY FOR THIS PROCEEDING?

A. Yes, I did.

Q. ARE YOU FAMILIAR WITH THE PRODUCTION DEMAND/ENERGY STUDY UTILIZED BY DUKE ENERGY INDIANA WITNESS MS. MARIA DIAZ IN HER COST OF SERVICE STUDIES?

A. Yes, I conducted the production demand/energy study and provided it to Ms. Diaz for her use.

Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, it does.

VERIFICATION

I hereby verify under the penalties of perjury that the foregoing representations are true to the best of my knowledge, information and belief.

Signed: ______________________
Keith B. Pike

Dated: 7/2/2019