STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY D/B/A CENTERPOINT ENERGY INDIANA SOUTH ("CEI SOUTH") FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE-IN OF RATES, (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, AND NEW AND REVISED RIDERS, INCLUDING BUT NOT LIMITED TO A NEW TAX ADJUSTMENT RIDER AND A NEW GREEN POWER RIDER (3) APPROVAL OF A CRITICAL PEAK PRICING ("CPP") PILOT PROGRAM, (4) APPROVAL OF REVISED DEPRECIATION RATES APPLICABLE TO ELECTRIC AND COMMON PLANT IN SERVICE, (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING AUTHORITY TO CAPITALIZE AS RATE BASE ALL CLOUD COMPUTING COSTS AND DEFER TO A REGULATORY ASSET AMOUNTS NOT ALREADY INCLUDED IN BASE RATES THAT ARE INCURRED FOR THIRD-PARTY CLOUD COMPUTING ARRANGEMENTS, AND (6) APPROVAL OF AN ALTERNATIVE REGULATORY PLAN GRANTING CEI SOUTH A WAIVER FROM 170 IAC 4-1-16(f) TO ALLOW FOR REMOTE DISCONNECTION FOR NON-PAYMENT	)	**CAUSE NO. 45990**

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

PUBLIC'S EXHIBIT NO. 12-S

SETTLEMENT TESTIMONY OF OUCC WITNESS DR. DAVID E. DISMUKES

July 19, 2024

Respectfully submitted,

T. Jason Haas
Deputy Consumer Counselor
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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David E. Dismukes. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana 70808.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed direct testimony in this proceeding on March 12, 2024, on behalf of the Indiana Office of Utility Consumer Counselor ("OUCC").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present an objection to the Stipulation and Settlement Agreement ("Settlement Agreement") filed jointly by Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("CEI South" or the "Company"), the CenterPoint Energy Indiana South Industrial Group ("Industrial Group") and SABIC Innovative Plastics Mt. Vernon, LLC ("SABIC") (collectively, the "Settling Parties") on May 20, 2024. In particular, I address the Settlement Agreement's flawed provisions regarding allocated cost of service, revenue distribution, and rate design.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The balance of my testimony is organized into the following sections:

- Section II: Overview of Settlement Agreement
- Section III: Affordability Issues
- Section IV: Allocated Cost of Service Study
- Section V: Revenue Distribution
- Section VI: Rate Design
- Section VII: Proposed TOU-CPP Pilot
- Section VIII: Conclusion and Recommendations

II. OVERVIEW OF SETTLEMENT AGREEMENT

Q. PLEASE PROVIDE AN OVERVIEW OF THE SETTLEMENT AGREEMENT AS IT RELATES TO CEI SOUTH'S OVERALL BASE REVENUE REQUIREMENT.

A. The Settling Parties propose an overall base revenue requirement for CEI South of $803.9 million, or an increase in current base rate revenues of approximately $80.0 million. This represents a decrease of $38.7 million from the Company's initial proposal or $35.4 million from the Company's updated request included in its Rebuttal Testimony.[1] This increase in base revenue requirement is based in part on an overall rate of return ("ROR") of 6.77 percent and a forecasted end-of-test year net rate base of $2.8 billion.[2]

Q. PLEASE SUMMARIZE THE SETTLEMENT AGREEMENT AS IT RELATES TO COST OF SERVICE AND REVENUE ALLOCATION.

A. The Settling Parties propose that CEI South's allocated cost of service study ("ACOSS") and revenue allocations be used with modifications.[3] Under the Settlement Agreement, CEI South's ACOSS will be modified such that generation and transmission costs are allocated to customer classes based on the average class contribution to coincident peak demand during the four summer months ("4 CP"),[4] and customer costs will be determined based upon the results of a minimum system study ("MSS").[5] In terms of revenue allocation, under the Settlement Agreement (1) no class receives a rate decrease as a result of this proceeding;[6]

[1] Stipulation and Settlement Agreement at B(2)(a).
[2] Stipulation and Settlement Agreement at B(3)(a) and B(3)(c).
[3] Stipulation and Settlement Agreement at B(13).
[4] Stipulation and Settlement Agreement at B(13)(a).
[5] Stipulation and Settlement Agreement at B(13)(b).
[6] Stipulation and Settlement Agreement at B(13)(c)(i).

(2) no class receives a rate increase that is higher than CEI South proposed in its updated revenue allocation proposal included in its Rebuttal Testimony;[7] (3) water heating customers receive a rate increase equal to 1.5 times the system average increase;[8] and (4) all other customer classes besides water heating receive no more than a rate increase equal to 1.35 times the system average increase.[9]

Q. HAVE YOU REVIEWED THE PROPOSED SETTLEMENT ALLOCATION AND COMPARED IT TO WHAT THE OUCC HAS RECOMMENDED?

A. Yes, and I have tabulated the differences in Tables 1 and 2 below.

Table 1: Settlement Agreement's Proposed Revenue Allocations

		Residential						Lighting	
Description	Total CEI South	Residential Service (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
Curent Revenues	$ 723,922,849	$ 319,622,569	$ 1,759,173	$ 14,704,649	$ 207,073,126	$ 167,222,380	$ 8,607,350	$ 1,836,828	$ 3,096,774
Proposed Increase	80,009,617	46,840,706	291,642	1,070,331	17,955,496	13,539,857	311,586	-	-
Proposed Revenues	$ 803,932,466	$ 366,463,275	$ 2,050,815	$ 15,774,980	$ 225,028,622	$ 180,762,237	$ 8,918,936	$ 1,836,828	$ 3,096,774
Percent Increase	**11.05%**	**14.66%**	**16.58%**	**7.28%**	**8.67%**	**8.10%**	**3.62%**	**0.00%**	**0.00%**
Relative Increase	**1.00**	**1.33**	**1.50**	**0.66**	**0.78**	**0.73**	**0.33**	**0.00**	**0.00**

Table 2: OUCC's Alternative Proposed Revenue Allocation

		Residential						Lighting	
Description	Total CEI South	Residential Service (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
Curent Revenues	$ 723,922,849	$ 318,179,438	$ 1,766,970	$ 14,693,952	$ 206,714,134	$ 168,795,811	$ 8,758,066	$ 1,868,087	$ 3,146,391
Proposed Increase	80,009,617	37,668,406	224,583	1,220,984	17,933,351	21,454,056	1,113,156	-	395,081
Proposed Revenues	$ 803,932,466	$ 355,847,844	$ 1,991,553	$ 15,914,936	$ 224,647,485	$ 190,249,867	$ 9,871,222	$ 1,868,087	$ 3,541,472
Percent Increase	**11.05%**	**11.84%**	**12.71%**	**8.31%**	**8.68%**	**12.71%**	**12.71%**	**0.00%**	**12.56%**
Relative Increase	**1.00**	**1.07**	**1.15**	**0.75**	**0.78**	**1.15**	**1.15**	**0.00**	**1.14**

Q. WHAT HAVE YOU CONCLUDED FROM THIS ANALYSIS?

A. The Settlement Agreement proposes to increase Residential rates by $47.1 million (14.67 percent), while the OUCC's recommendations would increase Residential

[7] Stipulation and Settlement Agreement at B(13)(c)(ii).
[8] Stipulation and Settlement Agreement at B(13)(c)(iii).
[9] Stipulation and Settlement Agreement at B(13)(c)(iii).

rates by $37.9 million (11.8 percent). The OUCC's proposed allocation reduces the proposed increase to residential customers by about $9.2 million, or 19.5 percent when compared to the Settlement.

Q. PLEASE SUMMARIZE THE SETTLEMENT AGREEMENT AS IT RELATES TO RATE DESIGN.

A. The Settlement Agreement proscribes specific class-by-class customer charges be applied to base rates. This includes small increases in base rate customer charges for RS and small general service ("SGS") rates from the current $10.84 per month to $11.00 per month. Importantly, the Settlement Agreement clarifies that the proscribed customer charges relate only to the fixed charge included in base rates without including the fixed portion of TDSIC recovery.[10]

Q. PLEASE SUMMARIZE THE SETTLEMENT AGREEMENT AS IT RELATES TO THE PROPOSED TOU-CPP PILOT AND RIDERS.

A. The Settling Parties stipulate that CEI South's TOU-CPP Pilot be approved, along with the Aggregated Demand Response ("Rider ADR") and the Green Energy Rider as proposed by CEI South in its initial filing. The Settlement Agreement provides no modifications to these proposals, except that parties be provided with copies of contracts with demand response aggregators after being signed.[11]

III. AFFORDABILITY ISSUES

Q. HOW DO THE SETTLING PARTIES ADDRESS AFFORDABILITY ISSUES?

[10] Stipulation and Settlement Agreement at B(14).
[11] Stipulation and Settlement Agreement at B(7)(a).

A. The Company in its settlement testimony argues that its rates have only increased at an average 2.1 percent compound annual growth rate since July 2011,[12] and that this low growth in rates will continue into the future. The Company estimates that average monthly electricity bills for a customer with monthly use of 500 kWh in Vanderburgh County will be $122.42, with an electric energy burden of 2.23 percent for a median income household.[13] The Company estimates that customers with average monthly electricity use of 799 kWh and 1,000 kWh will have average monthly bills of $189.05 and $233.84, respectively, with electric energy burdens of 3.45 and 4.27 percent, respectively, for a median income household.[14]

Q. DOES THE COMPANY CLAIM THAT THESE RATES REPRESENT AFFORDABLE RATES FOR ITS CUSTOMERS?

A. Yes. The Company argues the three electric use amounts listed (500; 799; 1,000 kWh per month) when combined with an average annual natural gas bill of $960.57 results in total energy burdens of 3.69, 4.91, and 5.73 percent.[15] The Company claims all of these results are below the six percent affordability threshold presented in my Direct Testimony.[16]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIMS REGARDING THE AFFORDABILITY OF ITS RATES?

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[12] Settlement Testimony of Matthew A. Rice at 24:25-28.
[13] Settlement Testimony of Matthew A. Rice at 25:9-11.
[14] Settlement Testimony of Matthew A. Rice at 25:11-14.
[15] Settlement Testimony of Matthew A. Rice at 25:17-19.
[16] Settlement Testimony of Matthew A. Rice at 25:19-20.

A. No. The Company's settlement analysis relies on the same flawed approach presented in its rebuttal. The Company's rebuttal testimony criticized my affordability analysis arguing that it incorrectly (1) removed rental costs from household income[17] and (2) utilized data from the entire Midwest to estimate income and usage rather than data from CEI South's territory.[18] CEI South presented individual affordability analyses for each of the seven counties it operates in based on median household income and median Company electric bills.[19] The Company argues its electric burden is between 2.01 and 2.93 percent depending on the county measured,[20] and that the total energy burden (i.e. both electric and natural gas burden) is between 3.92 and 5.95 percent system-wide depending on the assumed electric usage.[21]

Q. WHY DO YOU DISAGREE WITH THE COMPANY'S AFFORDABILITY ANALYSIS?

A. The Company's affordability analysis is significantly flawed because it assesses the affordability of the Company's rates to the <u>median</u> household (i.e. 50th percentile household) customer in the counties it operates in. By definition, half of the households within the Company's service territory have more difficulty paying for monthly utility bills than shown by the Company's analysis. It is for this reason that analyses examine affordability for low-and-moderate income households

[17] Rebuttal Testimony of Matthew A. Rice at 7:19-22.
[18] Rebuttal Testimony of Matthew A. Rice at 9:2-10.
[19] Rebuttal Testimony of Matthew A. Rice at 11, Table MAR-R5.
[20] Rebuttal Testimony of Matthew A. Rice at 11, Table MAR-R5.
[21] Rebuttal Testimony of Matthew A. Rice at 13:13-16.

rather than average-income households, such as those existing at the 15th and 20th percentile of regional household incomes.

Q. HAVE YOU CALCULATED REVISED ENERGY AFFORDABILITY STATISTICS FOR THE COMPANY'S RATES?

A. Yes. Exhibit DED-1-S presents eight revised statistics on electric affordability based on concerns the Company expressed. These analyses calculate the affordability of the Company's rates for customers existing at 15 and 20 percentile of household incomes in each of the seven counties the Company operates in and for the Company system-wide. This addresses the Company's earlier concern that my analysis inappropriately used income and usage data from the Midwestern region instead of data specific to the Company's service territory. This analysis also can be viewed as conservative since it removes rental costs from calculations of household disposable income, even though housing costs have been viewed by other regulatory commissions as a necessity that should be accounted for when calculating energy burdens.[22]

Q. WHAT ARE THE RESULTS OF YOUR REVISED AFFORDABILITY ANALYSIS?

A. Exhibit DED-1-S shows that the energy burden exceeds six percent system-wide for customers at or below the 15th percentile income level and nearly exceeding six percent for customers at the 20th percentile income level. On a county-specific basis, the analysis shows that the Company's rates currently exceed or will exceed this six percent affordability level for households reporting income at the 15th

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[22] *See*, *Order Instituting Rulemaking Develop Methods to Assess the Affordability Impacts of Utility Rate Requests and Commission Proceedings,* California Public Service Commission Rulemaking 18-07-006, Staff Proposal on Essential Service and Affordability Metrics (August 20, 2019).

percentile income level in all counties with the exception of Warrick County. The analysis also shows that households earning at the 20th percentile income level currently exceed or will exceed the six percent energy burden in Vanderburgh, Spencer, and Pike counties. Importantly, there is no universal definition of "unaffordability" and the six percent threshold quoted is intended to represent a level of extreme financial burden. Arguing that an energy burden of nearly six percent is somehow a positive is similar to attempting to reassure a flood victim that his or her circumstance is not that bad since they only got a few of feet of water in their home rather than being completely submerged.

IV. ALLOCATED COST OF SERVICE STUDY

A. Classification and Cost Allocation of Production Plant

Q. HOW DOES THE SETTLEMENT AGREEMENT CLASSIFY AND ALLOCATE COSTS ASSOCIATED WITH PRODUCTION PLANT FOR ACOSS PURPOSES?

A. The Settlement Agreement continues the flawed approach of the Company's ACOSS by classifying 100 percent of fixed production plant costs as demand-related, using a 4 CP approach to allocate costs to all customer classes.[23] The Settlement Agreement ignores the evidence presented by myself and Citizen Action Coalition of Indiana, Inc. ("CAC") showing that electric generation units ("EGUs") are designed and built to meet both the energy and demand requirements of the Company's customers.[24]

[23] Stipulation and Settlement Agreement at B(13)(a).
[24] *See* Direct Testimony of David E. Dismukes at 21:14-22; and Direct Testimony of Justin Barnes at 6:13 to 7:3.

Q. DO YOU AGREE WITH THE SETTLEMENT AGREEMENT'S CLASSIFICATION OF ALL FIXED PRODUCTION PLANT COSTS AS 100 PERCENT DEMAND RELATED?

A. No. The Settlement Agreement's approach continues the flawed logic of the Company's ACOSS included in its initial filing that the only purpose of EGUs is to support maximum system demands during a few hours of the year, ignoring the role these assets play in providing low-cost energy requirements for off-peak periods on the Company's system. Equally important, the Company's proposed classification ignores the significant portion of its current production plant in service that is associated with renewable generation assets, which provide very limited capacity benefits and should not be exclusively classified as demand related.

Q. HOW DO EGUs BOTH SUPPORT MAXIMUM SYSTEM DEMANDS DURING PEAK PERIODS AND PROVIDE LOW-COST ENERGY DURING OFF-PEAK PERIODS?

A. The electric utility industry is somewhat unique in that there is an energy/capacity trade-off relating to production costs, requiring a utility to design a diversified set of EGUs in its system dispatch that minimize both variable and fixed costs while ensuring there is enough available capacity to meet peak demand requirements. For example, the total capital investment cost associated with the Company's F.B. Culley Station is $1,474 per kW of installed capacity, but it operated relatively efficiently compared to other units at only $0.05 per kWh in 2022.[25] At the other end of the spectrum, both of the Company's current combustion turbine units at

[25] *See* Company's 2022 FERC Form 1.

A.B. Brown Station (A.B. Brown Station Units 3 and 4) have total capital investment costs of approximately $350 per kW of installed capacity. However, these combustion turbine units also operated inefficiently when compared to the Company's F.B. Culley Station, incurring approximately $0.134 per kWh of generation in 2022.[26] In this, F.B. Culley Station demonstrates characteristics of a "baseload" unit that is relatively expensive to construct (more than four times the cost of A.B. Brown Station Units 3 and 4), but inexpensive to operate (nearly a third the operating costs of A.B. Brown Station Units 3 and 4) and, thus, designed to serve steady, consistent, multi-hour energy loads, while A.B. Brown Station Units 3 and 4 are peaking units that are relatively inexpensive to build, but expensive to operate and, thus, designed to serve load requirements only when required.

Q. HOW DO THESE OPERATIONAL PARAMETERS IMPACT THE COST OF SERVICE?

A. If the sole consideration when constructing an EGU was ensuring there are sufficient resources to meet peak system load requirements, as argued by the Settling Parties, a prudent utility would only construct natural gas combustion turbine peaking units such as A.B. Brown Station Units 3 and 4, since these units are inexpensive to construct relative to the generation capacity they provide, eschewing all baseload generation facilities. Of course, the expensive and likely uncertain operational costs of a generation fleet comprised solely of natural gas peaking units are why a utility does not configure their generation resources in

[26] *See* Company's 2022 FERC Form 1.

such a manner. The Michigan Public Service Commission ("MPSC") recognized this reality in a 2015 review of cost-of-service allocations for DTE Electric Company.

> The Commission agrees with the Staff, the Attorney General, Energy Michigan, and [Environmental and Consumer Advocates] that DTE Electric's production system was not designed and built solely for the purpose of providing capacity for four hours a year. Indeed, if that were the case, DTE Electric's generation asset portfolio would be very different and would certainly include far fewer of the large base load units that comprise much of the company's current fleet. Instead of building a system to simply meet demand, the company developed its production plant to both deliver energy and provide capacity at the lowest <u>overall</u> cost to <u>all</u> customers who use the system. Thus, DTE Electric's generating system includes a mix of base load plants that were significant investments, but that provide abundant, reliable, and low-cost energy to all customers, and peaking plants, with low fixed production costs and typically higher fuel costs than the base load units. These peaking plants are the units that are used to meet peak demand in the summer months.[27]

Q. HOW DO RENEWABLE EGUs IMPACT ELECTRIC SYSTEM OPERATIONS?

A. Intermittent renewable EGUs are distinct from traditional fossil-fuel based generation, providing very little capacity benefits due to the intermittent nature of the generation source – wind turbines and solar photovoltaic cells can only generate electricity when the wind is blowing or the sun is shining. However, these generators produce electricity at very low costs, since these units have fuel sources (i.e. wind and the sun) that are free, for all intents and purposes.

[27] *In re the Commission's own motion to commence a proceeding to implement the provisions of Public Act 169 of 2014; MCL 460.11 (3) et seq., with regard to DTE Electric Company.* Case No. 17689, Opinion and Order (Mich. Pub. Serv. Comm'n June 15, 2015).

Q. DOES THE COMPANY RECOGNIZE THE UNIQUE NATURE OF RENEWABLE GENERATION UNITS COMPARED TO TRADITIONAL FOSSIL-FUEL BASED GENERATION?

A. Yes. In the Company's 2022/2023 Integrated Resource Plan ("2022/2023 IRP"), the Company discussed the distinct operational concern of transitioning to generation resources with limited ability to assist in meeting peak demand requirements.

> Traditionally, baseload coal plants produce energy at a constant level around the clock, while peaking gas plants were available to come online as needed to meet peak demand. Gradual increases and decreases in energy demand throughout the day and seasonally were easily managed with these traditional resources. As described above, <u>the energy landscape is continuing its rapid change with increased adoption of more intermittent renewable generation which is available when the sun is shining, or the wind is blowing. This creates much more variability by hour in energy production. Some periods will have over production (more energy produced than is needed at the time) and other periods will have low to no renewable energy production, requiring dispatchable resources to meet real time demand for power.</u> MISO has recognized the region's energy landscape continues to evolve toward a complex, less predictable future. Some of the challenges MISO faces are resources that are primarily weather dependent, less predictable weather, less predictable resource outages, and increasing electric load. To maintain reliability with a changing resource portfolio and the risks MISO faces there is an increased importance of ensuring there are adequate attributes available from the fleet such as ramp capability, long duration energy at high output, and fuel assurance. <u>To ensure reliability is maintained with the changing resource portfolio, MISO implemented a seasonal resource adequacy construct for the 2023/2024 planning year that focuses on meeting system demand in all hours as opposed to planning for meeting the summer peak demand.</u> As

> part of the seasonal construct thermal resource accreditation has shifted from an Equivalent Forced Outage Rate Demand ("EFORd") approach to one that accredits resources based on historical availability during tight operating hours. Accreditation for renewable resources has also seen changes with MISO signaling it will continue to revise the accreditation approach for renewables for upcoming planning years. MISO continues to study how this transition will affect the electrical grid and what is needed to maintain reliable service, as renewables penetrations reach 30-50%.[28]

Q. HAS THE COMMISSION PREVIOUSLY RECOGNIZED THE UNIQUE NATURE OF RENEWABLE GENERATION UNITS COMPARED TO TRADITIONAL FOSSIL-FUEL BASED GENERATION?

A. Yes. In approving the Company's proposal for a new generation facility, the Commission explicitly recognized the requirement to maintain peaking fossil fuel EGUs to ensure the Company's ability to meet requirements during system peak demand periods with the addition of intermittent resources.

> Due to the intermittency of the renewable resources in the Preferred Portfolio, resources with quick ramp capabilities are necessary to complement the addition of such intermittent resources to the system to ensure reliability.[29]

Q. IS APPROPRIATELY ACCOUNTING FOR INTERMITTENT RENEWABLE GENERATION IMPORTANT AT THE CURRENT JUNCTURE?

A. Yes. The Commission last approved an ACOSS for the Company in 2018. However, as shown in Exhibit DED-2-S, the Company includes three new EGUs

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[28] 2022/2023 Integrated Resource Plan (May 2023) at 47 (*emphasis added*).
[29] *Petition of S. Ind. Gas & Elec. Co. d/b/a CenterPoint Energy Indiana South for Issuance of a Certificate of Public Convenience and Necessity for the Construction of Two Natural Gas Turbines*, Cause No. 45564, Final Order at 17 (Ind. Util. Regul. Comm'n June 28, 2022).

in its forecasted test year rate base which were not operational in 2018. Of these three, two are renewable in nature. Whereas in 2018 only 9.6 percent of the Company's net production plant in service was associated with renewable generation units, 53.0 percent of the Company's test year net production plant in service is now associated with renewable generation units.

Q. HAS THE COMPANY MADE ANY OBSERVATIONS ABOUT THE ACCREDITED CAPACITY RATING OF INTERMITTENT RENEWABLE GENERATION?

A. Yes. The Company's 2022/2023 IRP noted that the Midcontinent Independent System Operator ("MISO") has signaled that it expects capacity accreditations for intermittent renewable generation resources to decline over time as more such resources are brought online.[30] This emphasizes the need to develop a structure to appropriately account for the operational differences in renewable generation versus traditional fossil fuel generation for cost-of-service purposes at the current juncture.

> MISO has shifted from 96% dispatchable generation (all forms of generation except renewables) in 2005 to approximately 76% currently and is forecasted to be greater than 40% renewables in 2031. In response to these conditions MISO commenced its Resource Availability and Need ("RAN") Initiative and its Renewable Integration Impact Assessment ("RIIA") to plan market rule changes to deal with the future resource mix. The RAN Initiative is aimed at better accrediting generation units while the RIIA is focused on understanding the impacts of renewable energy growth in MISO over the long term and assessing potential transmission solutions to mitigate them. <u>While MISO continues to evaluate methodologies for future intermittent resource accreditation, it has signaled</u>

[30] 2022/2023 Integrated Resource Plan (May 2023) at 151.

accreditation will likely decline over time, particularly for solar resources, as more renewable resources are brought into service.[31]

Q. DOES THE ALTERNATIVE ACOSS PROPOSED IN YOUR DIRECT TESTIMONY APPROPRIATELY ACCOUNT FOR THE OPERATIONAL DIFFERENCES IN RENEWABLE GENERATION VERSUS TRADITIONAL FOSSIL FUEL-BASED GENERATION?

A. Yes. As explained in my Direct Testimony, MISO's current process for accrediting solar photovoltaic resources is based on three years of historical output, with new solar resources accredited at 50 percent of nameplate capacity for spring, summer, and fall months.[32] Using this information, I determined 26.2 percent of the Company's test year net plant in service should be classified as 100 percent energy-related, with the remainder classified as serving joint demand and energy functions.[33]

Q. DID THE COMPANY FIND THE PROPOSED TREATMENT OF COSTS ASSOCIATED WITH RENEWABLE GENERATION RESOURCES ACCEPTABLE?

A. Yes. The Company argues renewable resources contain a "swapping of steel for fuel" aspect and that the Effective Load Carrying Capability ("ELCC", i.e. the accredited capacity) of intermittent renewable resources is low and will decline further as renewable penetrations increase.[34] The Company, thus, agrees that it is appropriate to classify a portion of renewable generation resources as energy-

[31] 2022/2023 Integrated Resource Plan (May 2023) at 151 (emphasis added).
[32] Direct Testimony of David Dismukes at 34:3-8.
[33] Direct Testimony of David E. Dismukes at 34:11-18 and Exhibit DED-8.
[34] Rebuttal Testimony of John D. Taylor at 16:14-16.

related, and that specifically the method I proposed relying on MISO capacity accreditation for individual renewable resources would be the correct approach to implement this classification.[35]

> While the system is planned as a single, integrated system; intermittent renewable resources have distinct characteristics which require the examination and allocation of those resources independent of the firm, dispatchable resources on the CEI South system. As I alluded to earlier, there is a "swapping of steel for fuel" aspect associated with renewable resources and the ELCC of intermittent renewable resources is low and will further decline as the penetration increases. The former (swapping steel for fuel) also aligns well contextually with the fuel symmetry associated with traditional fossil plants that are the IURC has recognized when classifying all fixed plant as demand related then allocating the corresponding costs to the average of customer demands in the requisite hours that best reflect those currently driving investment in capacity, and allocating average fuel to classes on an average energy basis… <u>Consequently, it would be appropriate to classify and/or allocate a portion of those resources using an energy measure. This aligns with the MidAmerican case that is referenced by OUCC Witness Dismukes</u> (though care must be taken as the MidAmerican system is at a far greater penetration of renewable resources and this is a distinguishing factor that must be considered in planning and operations, and so it must in cost allocation as well).[36]

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE APPROPRIATE CLASSIFICATION OF COSTS RELATED TO PRODUCTION PLANT?

A. I recommend the Commission reject the proposed Settlement Agreement for inappropriately classifying all fixed costs associated with production plant assets as being 100 percent demand-related: 53.0 percent of the Company's test year

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[35] Rebuttal Testimony of John D. Taylor at 16:11 to 17:1.
[36] Rebuttal Testimony of John D. Taylor at 16:11 to 17:1 (emphasis added).

net production plant in service will be associated with renewable generation assets, compared to as little as 9.6 percent previously. This represents a significant change in the operational characteristics of CEI South's system, as both the Company and the Commission have previously recognized the distinct nature of intermittent renewable generation resources when compared to traditional resources. The transition to generation that is more renewable-focused will also change how traditional resources are designed and operated, as these units have increasingly been used to support resource adequacy during shortfalls in renewable generation, rather than simply used to ensure resource adequacy during periods of peak system utilization.

B. Cost Allocation of Transmission Plant

Q. HOW DOES THE SETTLEMENT AGREEMENT ALLOCATE COSTS ASSOCIATED WITH TRANSMISSION PLANT FOR ACOSS PURPOSES?

A. The Settlement Agreement relies on 4 CP to allocate transmission plant costs.[37] This is distinct from the approach the Company used in its ACOSS included in its initial filing, which used a 12-month average of monthly coincident peak demands ("12 CP") to allocate costs associated with transmission plant.[38]

Q. DO YOU SUPPORT THE SETTLING PARTIES' PROPOSED ALLOCATION OF COSTS ASSOCIATED WITH TRANSMISSION PLANT?

A. No. A 12 CP approach is consistent with the approach MISO uses to allocate network transmission costs.[39] Importantly, as a member of MISO, the planning

[37] Settlement Testimony of John D. Taylor at 4:15-16.
[38] Direct Testimony of John D. Taylor at 11:17-19.
[39] Rebuttal Testimony of John D. Taylor at 19:11-13.

and operations of CEI South's transmission system are overseen by MISO.[40] Additionally, the Company expressed concerns in its initial filing that future transmission operations will shift away from single periods of peak demand during summer months toward periods of high renewable production and lower loads occurring in the spring and fall with increased integration of renewable generation systems to the electric grid.[41] The 12 CP cost allocation method is used by many state regulators to assure consistency in the cost allocation of transmission facilities between retail and wholesale operations.

C. Use of a Minimum System Study to Classify Distribution Plant Costs

Q. HOW DOES THE SETTLEMENT AGREEMENT PROPOSE TO CLASSIFY AND ALLOCATE COSTS ASSOCIATED WITH DISTRIBUTION PLANT FACILITIES?

A. Consistent with the Company's proposed ACOSS included in its initial filing, the Settlement Agreement relies on the results of a MSS to classify 56 percent of costs associated with FERC Account 368 – Line Transformers as customer-related.[42]

Q. DO YOU AGREE WITH THE PROPOSED ALLOCATION OF LINE TRANSFORMERS BASED ON THE RESULTS OF AN MSS?

A. No. As I explained at length in my Direct Testimony, the theoretical basis for MSS and related approaches is seriously flawed, and these studies provide little to no value regarding cost causation. Indeed, in modern operations very little distribution capital investment is related to serving new customers or other growth activities. As shown by Exhibit DED-3-S, on average only 9.6 percent of total non-TDSIC

[40] Rebuttal Testimony of John D. Taylor at 19:11-13.
[41] Direct Testimony of John D. Taylor at 12:12 to 13:1.
[42] Direct Testimony of John D. Taylor, Attachment JDT-2.

Distribution capital investments for the years 2023 through 2025 is expected to be associated with growth activities. Instead, most capital investments for the Company are expected to be associated with reliability-focused distribution system improvements or replacement of existing facilities.

Q. HAVE YOU EXAMINED HISTORIC COMPANY INVESTMENTS IN LINE TRANSFORMERS?

A. Yes. Exhibit DED-4-S shows net distribution plant additions to FERC Account 368 – Line Transformers for the years 2004 through 2022. Exhibit DED-4-S also shows changes in the average number of Company customers each year. Exhibit DED4-S shows that Company investment in Line Transformers is actually slightly negatively correlated with changes in the average number of Company customers (correlation coefficient of -0.178). As discussed in my Direct Testimony, empirical examination of the concept that investment in distribution plant facilities is related to interconnecting customers to the grid consistently shows little to no support for this idea.

V. REVENUE DISTRIBUTION

Q. HOW DO THE SETTLING PARTIES PROPOSE TO APPORTION REVENUES AMONG CUSTOMER CLASSES?

A. The Settling Parties propose a revenue distribution that is conceptually similar to the approach presented in the Company's initial filing. However, the Settlement Agreement additionally requires that: (1) no class receive a rate decrease as a result of the rates implemented pursuant to the Settlement Agreement; (2) no class receive a rate increase that is higher than what CEI South proposed in its rebuttal position; (3) the water heating service class receive a rate increase equal to 1.5 times the system average increase, and (4) all other customer classes besides the water heating service class receive a rate increase no greater than 1.35 times the system average.[43]

Q. DO YOU AGREE WITH THE PROPOSED REVENUE DISTRIBUTIONS UNDER THE SETTLEMENT AGREEMENT?

A. No. The Settlement Agreement's revenue distributions suffer from two major deficiencies. First, the Settling Parties' proposal is based on the results of a faulty ACOSS that overstates the extent of any current subsidy from high-load factor industrial customers to low-load factor residential customers. Second, the Settlement Agreement's proposed caps on rate increases are inconsistent with rate gradualism and could also negatively impact energy affordability, particularly for the Company's low- and middle-income customers.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE SETTLEMENT AGREEMENT'S PROPOSED REVENUE DISTRIBUTION?

A. I recommend the Commission reject the revenue distribution proposed in the Settlement Agreement as not being in the public interest. Instead, I recommend the Commission adopt a more reasonable revenue distribution allocation method based on my alternative ACOSS results that also limits the rate increase to any single customer class to 1.15 times the overall system average increase, consistent with the approach outlined in my Direct Testimony.

[43] Settlement Testimony of John D. Taylor at 6:15-22.

Q. HAVE YOU PREPARED A SUMMARY OF THE EFFECTS OF YOUR PROPOSED REVENUE DISTRIBUTION?

A. Yes. Exhibit DED-5-S presents an updated illustrative summary of the effects of my proposed revenue distribution under the Settlement Agreement's proposed system average rate increase. My proposed revenue distribution would allow a base rate increase for the residential class of 11.8 percent, compared to the Settlement Agreement's proposal which would increase such rates by 14.8 percent, a reduction of approximately $9.2 million.

VI. RATE DESIGN

Q. PLEASE SUMMARIZE THE SETTLEMENT AGREEMENT AS IT RELATES TO RATE DESIGN.

A. The Settlement Agreement proscribes specific class-by-class customer charges to be applied to base rates. This includes small increases in base rate customer charges for RS and SGS rates from the current $10.84 per month to $11.00 per month. Importantly, the Settlement Agreement clarifies that the proscribed customer charges relate only to the fixed charge included in base rates and do not include the fixed portion of TDSIC recovery.[44]

Q. DO YOU AGREE WITH THE SETTLEMENT AGREEMENT'S PROPOSED CUSTOMER CHARGES?

A. No. The Settlement Agreement does not address the critical issue of the current fixed cost recovery component of the Company's TDSIC.[45] The Company

[44] Stipulation and Settlement Agreement at B(14).
[45] Stipulation and Settlement Agreement at B(14).

currently recovers portions of monthly TDSIC charges assessed to RS, residential water heating service, and SGS customers partially on a fixed basis.[46] No other jurisdictional Indiana utility recovers monthly TDSIC charges based partially on a fixed charge basis.[47]

Q. HOW DOES THE FIXED TDSIC CHARGE FOR RS AND SGS CUSTOMERS AFFECT RATE DESIGN?

A. The fixed TDSIC charge for RS and SGS customers effectively acts as an additional customer charge on top of the customer charge included in base rates. As I showed in my Direct Testimony, the Company's current $10.84 customer charge for RS customers exceeds the regional average of $10.72 before including the fixed TDSIC charge. Including the fixed TDSIC charge of $6.50 makes the current RS customer charge the second highest in the region, second only to Kentucky Power Company's fixed charge of $17.50 per month.

Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS AND CONCLUSIONS?

A. I recommend the Commission reject the proposed Settlement Agreement's proposed customer charges. Instead, I reiterate the recommendation presented in my Direct Testimony that the Commission direct the Company to eliminate its current fixed component for monthly TDSIC charges for Rates RS, SGS, and water heating service customers, instead assessing monthly TDSIC charges fully as volumetric energy charges. The Company's current base customer charges for Rates RS and SGS are in-line with regional customer charges and recover more

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[46] CenterPoint Energy Indiana South Tariff, Sheet 75.
[47] *See* Company's Response to OUCC 18.1.

than fifty percent of monthly customer-related costs for these customer classes.[48] Maintaining the current practice of inflating the Company's monthly customer charge through fixed TDSIC charges detrimentally impacts the public policy goals of promoting energy efficiency and affordability, and burdens low-use customers.

VII. PROPOSED TOU-CPP PILOT

Q. PLEASE SUMMARIZE THE SETTLEMENT AGREEMENT AS IT RELATES TO THE PROPOSED TOU-CPP PILOT AND RIDERS.

A. The Settlement Agreement stipulates that CEI South's TOU-CPP Pilot be approved, along with the Aggregated Demand Response ("Rider ADR") and the Green Energy Rider as CEI South proposed in its initial filing. The Settlement Agreement provides no modifications to these proposals, except that parties be provided with copies of contracts with demand response aggregators after being signed.[49]

Q. DID YOU RAISE CONCERNS REGARDING THE TOU-CPP PILOT IN YOUR DIRECT TESTIMONY?

A. Yes. I noted several concerns with the TOU-CPP Pilot. Principal among these is the fact that the proposed TOU-CPP Pilot lacks evaluation criteria or clearly defined goals.

Q. HAVE THE COMPANY OR THE SETTLEMENT AGREEMENT ADDRESSED YOUR CONCERNS?

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[48] *See* Direct Testimony of David E. Dismukes at 47:16-19: "Costs can be instructive in establishing a baseline upon which prices may be set, but costs do not need to serve as the sole or exclusive basis for rates in order for them to be set optimally (*i.e.*, fixed charges do not need to strictly equal fixed costs, variable rates need not strictly equal variable costs)."
[49] Stipulation and Settlement Agreement at B(7)(a).

A. No. The Company in rebuttal stated the over-arching goal of the proposed pilot is to help the Company assess potential use cases and the cost-effectiveness of TOU rates,[50] and so the Company is still working with its evaluator to finalize evaluation criteria associated with the pilot.[51] The few evaluation criteria the Company has put forward associated with the TOU-CPP pilot are lacking the specifics required for such a pilot.[52]

Q. CAN YOU EXPLAIN HOW THE COMPANY'S CURRENT EVALUATION CRITERIA FOR USE WITH ITS PROPOSED TOU-CPP PILOT ARE LACKING IN SPECIFICS?

A. Yes. The Company states that it will evaluate the average kW demand impact per participant during on-peak hours, off-peak hours for the proposed TOU rate, and during CPP events.[53] However, importantly, the Company has not established any marker for potential load shifting it would realistically seek to accomplish through the proposed pilot program and, thus, any parameter for which success could be declared for the pilot. Similarly, the Company states that it will evaluate kWh energy savings from CPP events without establishing a prior baseline for estimated energy savings associated with the proposed Pilot. Perhaps most egregious, the Company states that it will measure bill impacts from the proposed pilot, but the Company does not establish either a baseline savings estimate to judge performance from or, importantly, establish the level of negative bill impacts (i.e. increased bills due to the pilot) the Company would find unacceptable.

[50] Rebuttal Testimony of Matthew A. Rice at 30:23-26.
[51] Rebuttal Testimony of Matthew A. Rice at 31:6-7.
[52] Rebuttal Testimony of Matthew A. Rice at 31.
[53] Rebuttal Testimony of Matthew A. Rice at 31.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE PROPOSED TOU-CPP PILOT?

A. I recommend the Commission not approve the proposed TOU-CPP Pilot. The program as proposed by the Company lacks clearly defined goals and objectives and information on how progress or achievement of these goals will be measured in the future. The proposed Settlement Agreement does not allay these concerns, and thus should be rejected.

VIII. CONCLUSION AND RECOMMENDATIONS

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE SETTLEMENT AGREEMENT?

A. I recommend the Commission reject the Settlement Agreement as not in the public interest. The Settlement Agreement would result in rate increases for low-load factor customers like RS customers that are not consistent with cost of service and would only contribute to and exacerbate the current unaffordability of CEI South's rates. The Settlement Agreement also does not address important public concerns such as the current high fixed cost recovery for base rates and the TDSIC, and the flaws in the Company's proposed TOU-CPP Pilot.

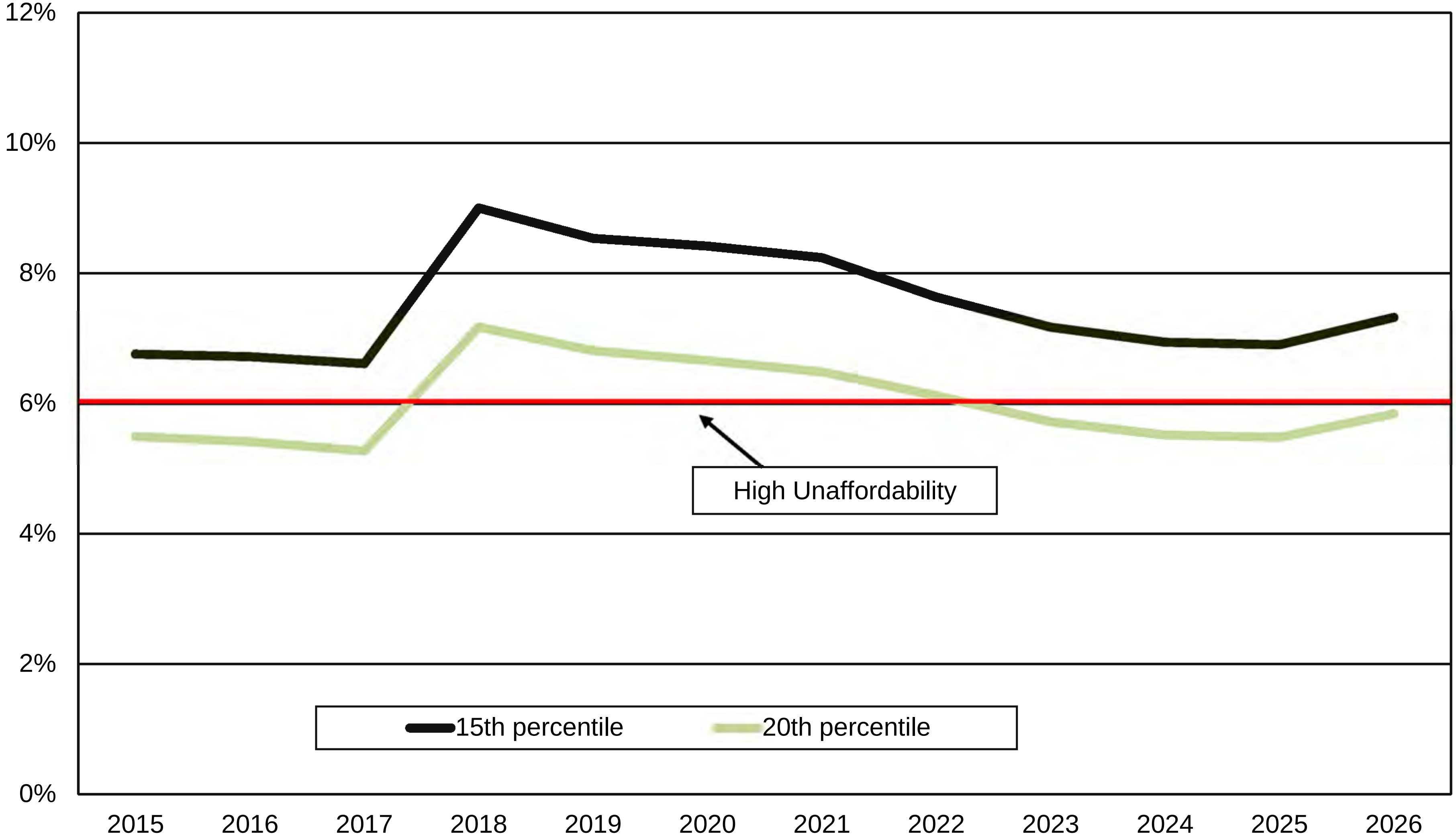
Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

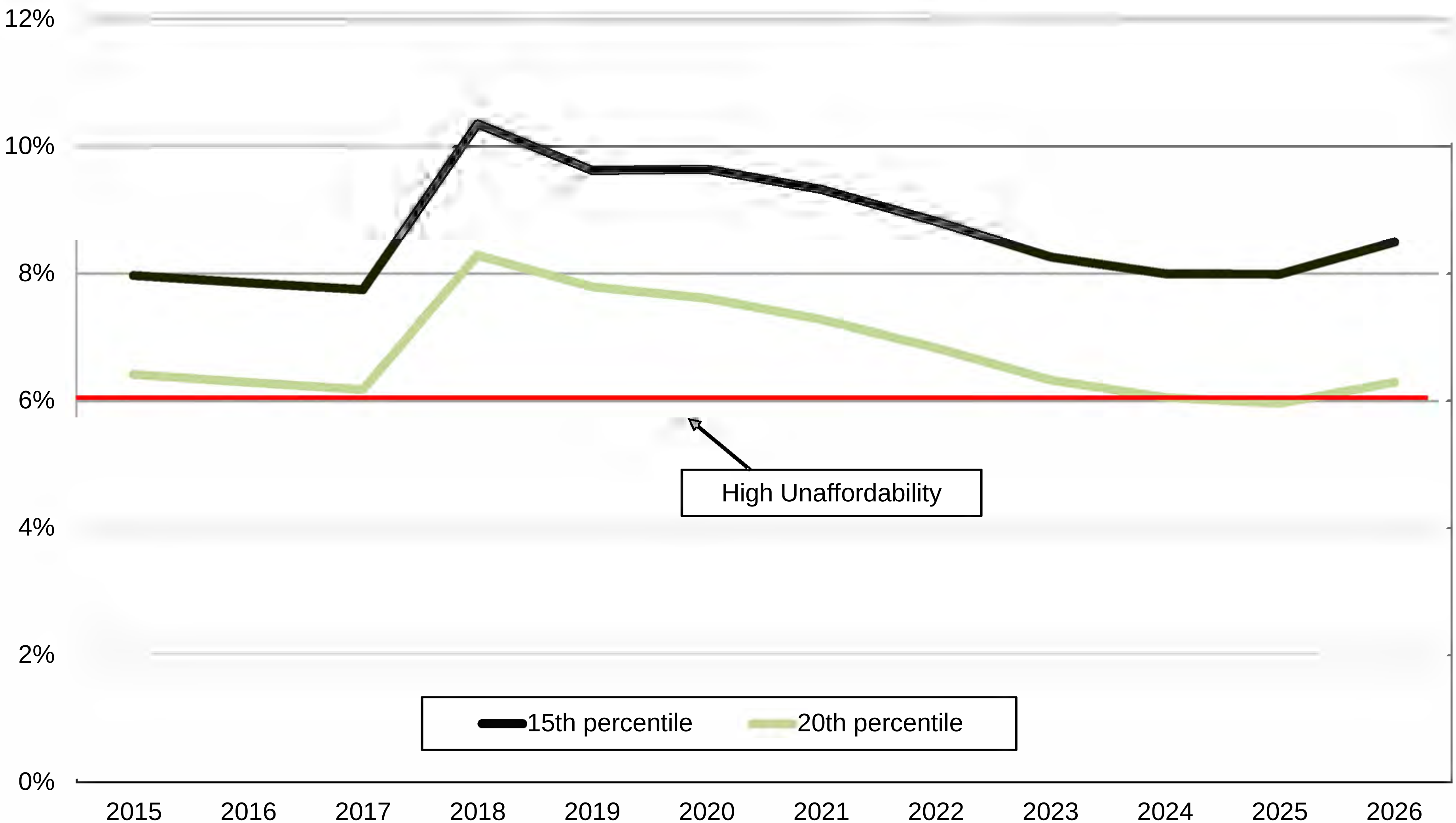
Table of Exhibits

Title	Exhibit
County-level CEI South Energy Affordability	Exhibit DED-1-S
Comparison of Production Plant, 2018 to 2024	Exhibit DED-2-S
Estimated Transmission and Distribution Plant Capital Investments, 2024-2025	Exhibit DED-3-S
Correlation between Customer and Line Transformer Investments, 2004-2022	Exhibit DED-4-S
Results of Alternative Revenue Distribution at Settlement Revenue Requirement	Exhibit DED-5-S

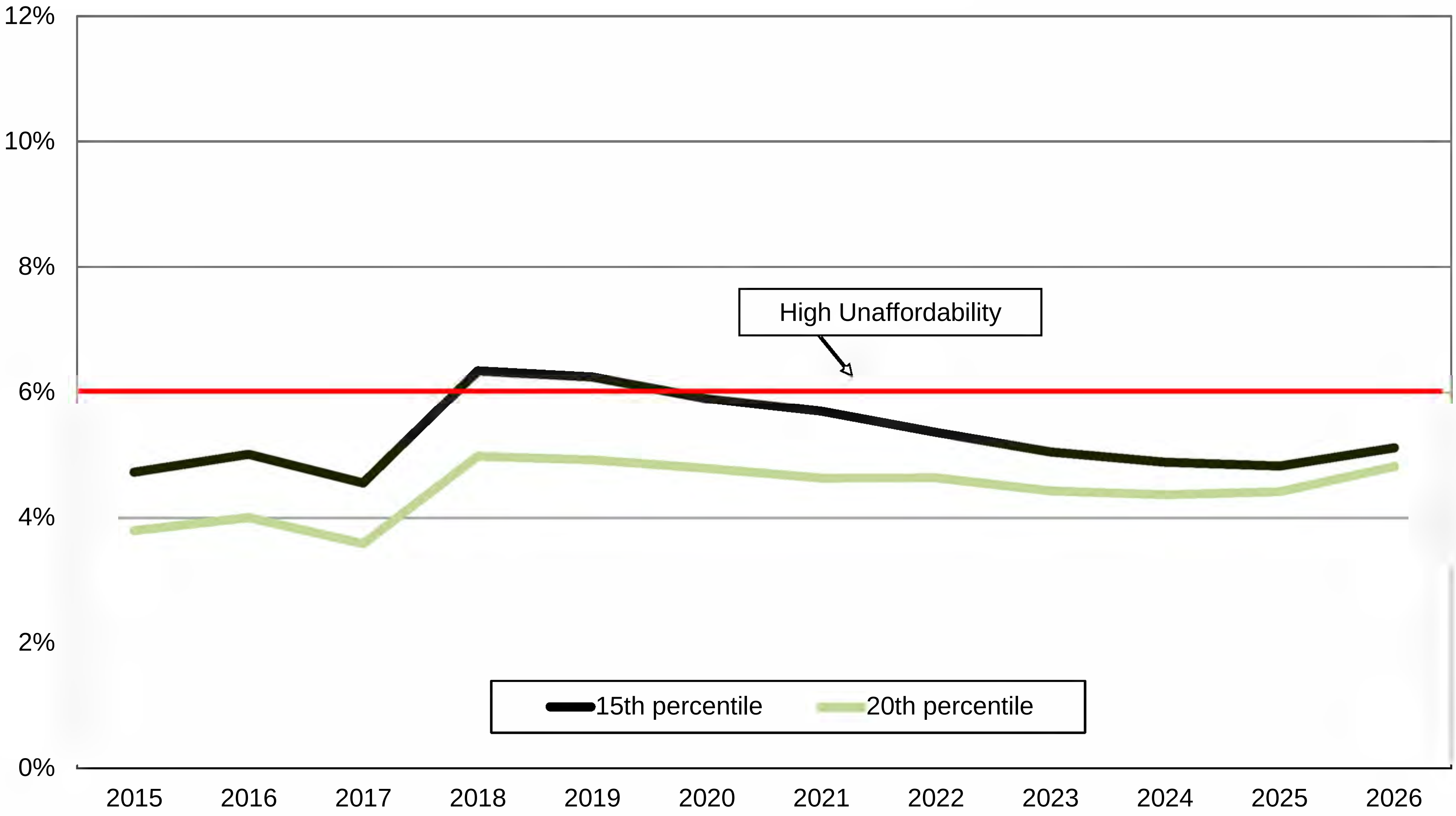
County-level CEI South Energy Affordability:
Total CEI South Service Territory



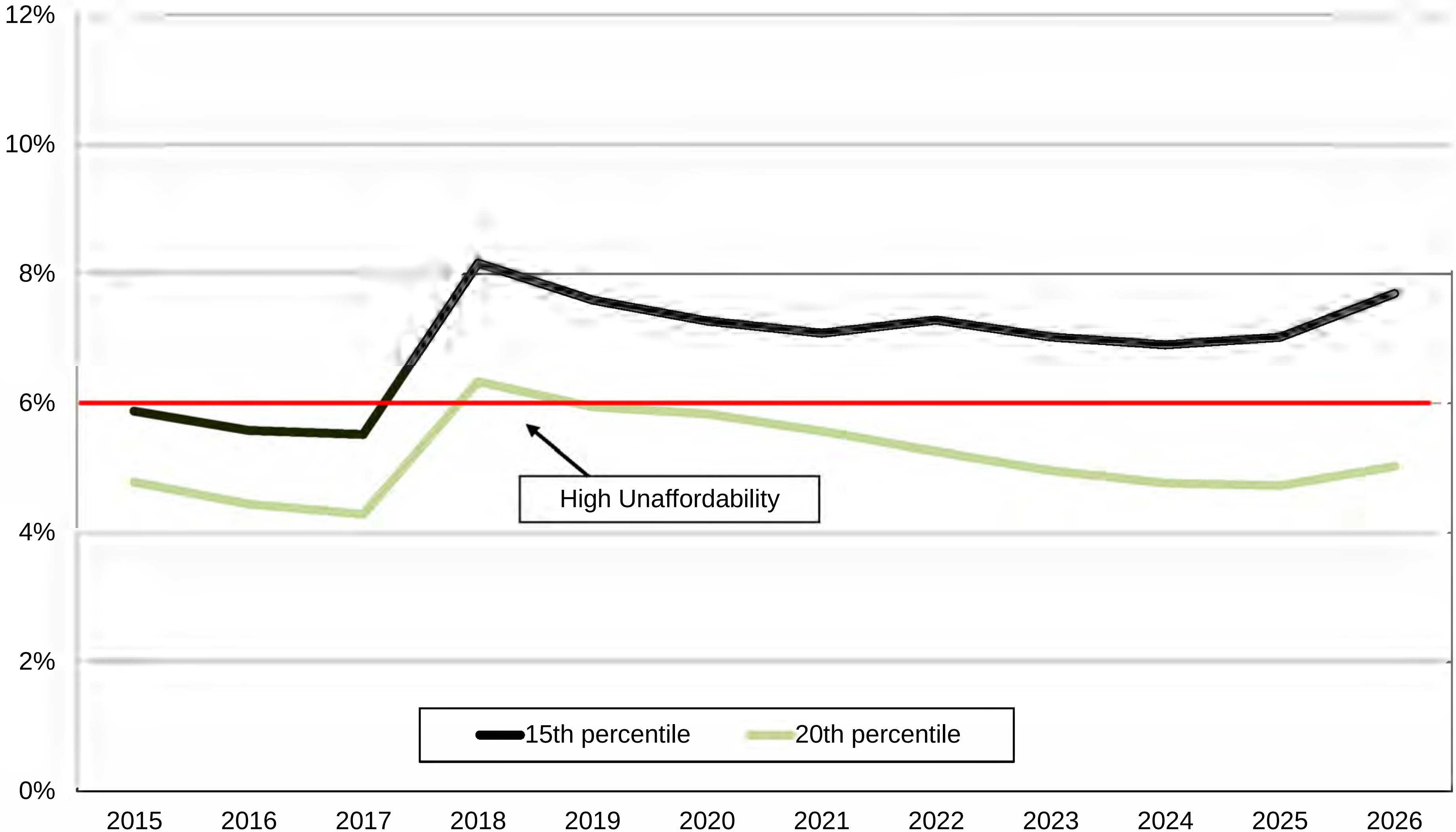
County-level CEI South Energy Affordability: Vanderburgh County



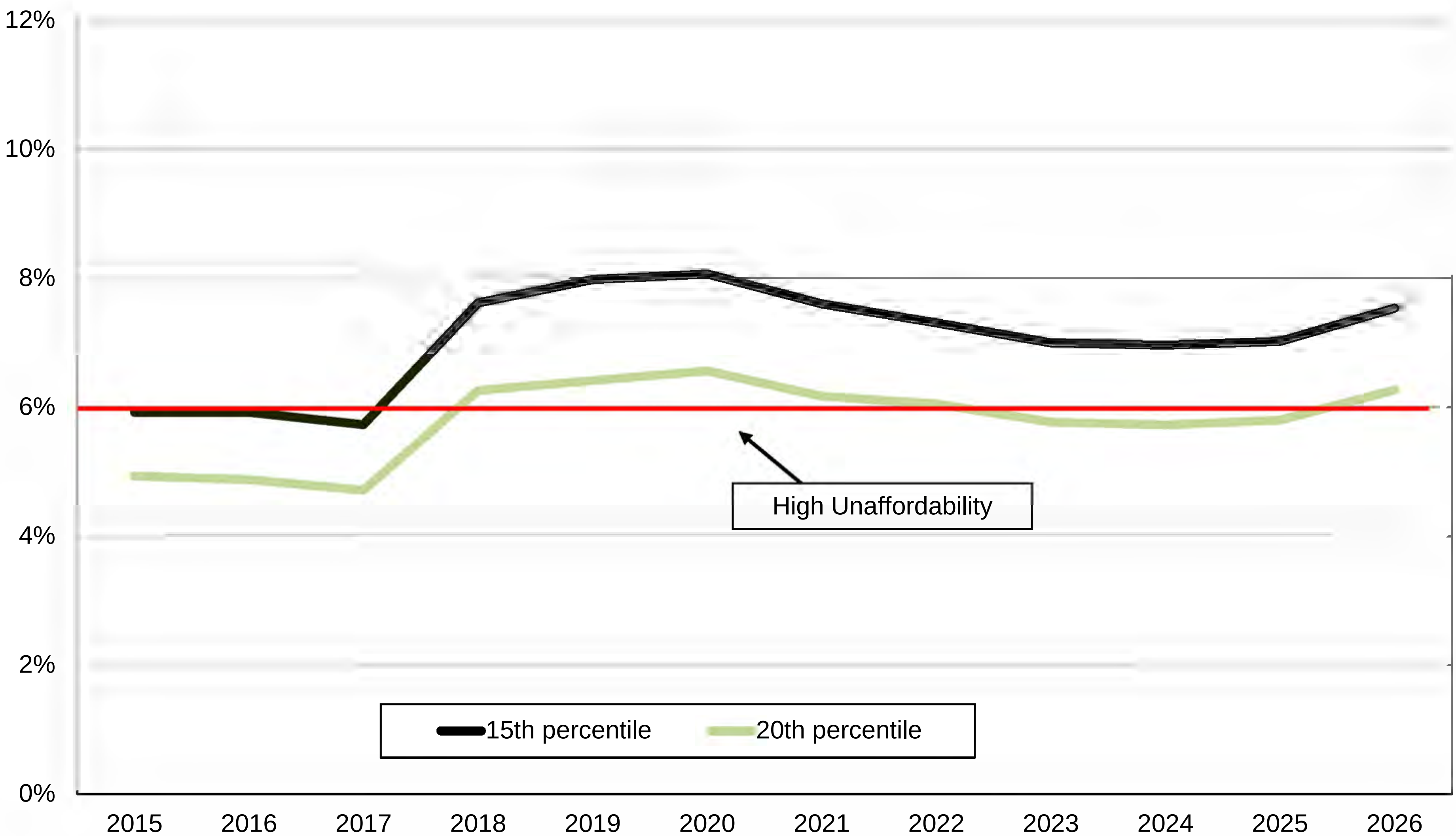
County-level CEI South Energy Affordability: Warrick County



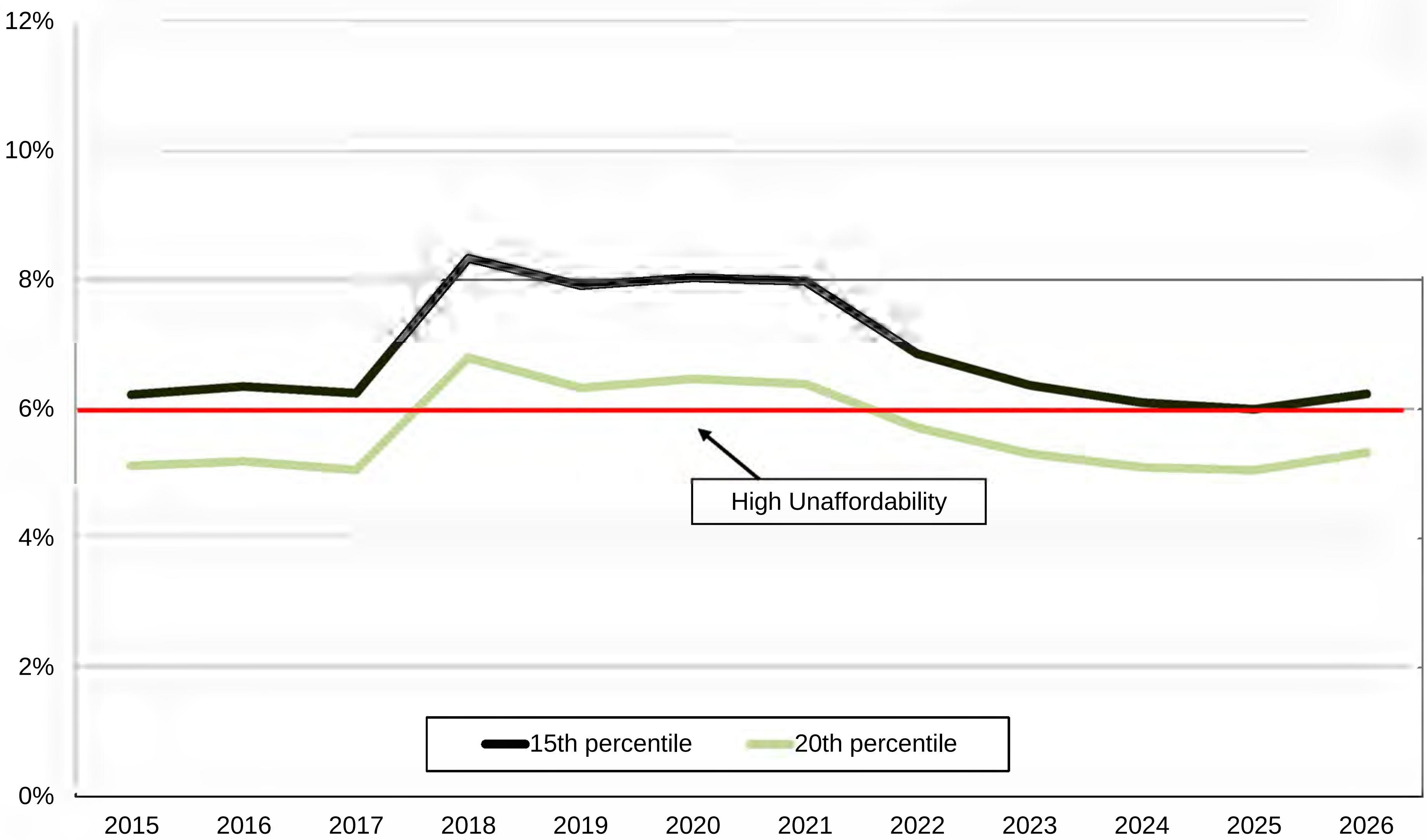
County-level CEI South Energy Affordability: Posey County



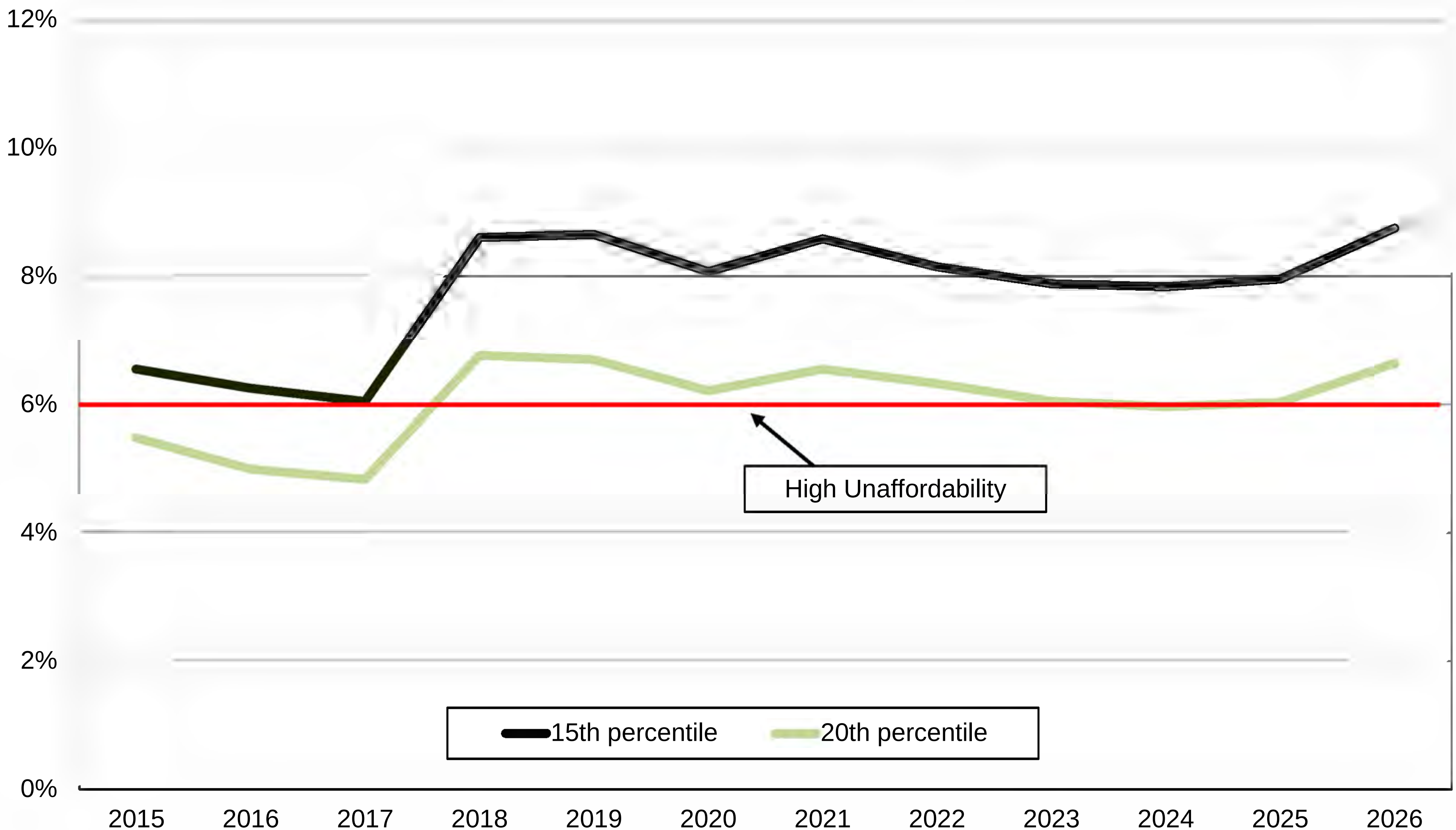
County-level CEI South Energy Affordability: Spencer County



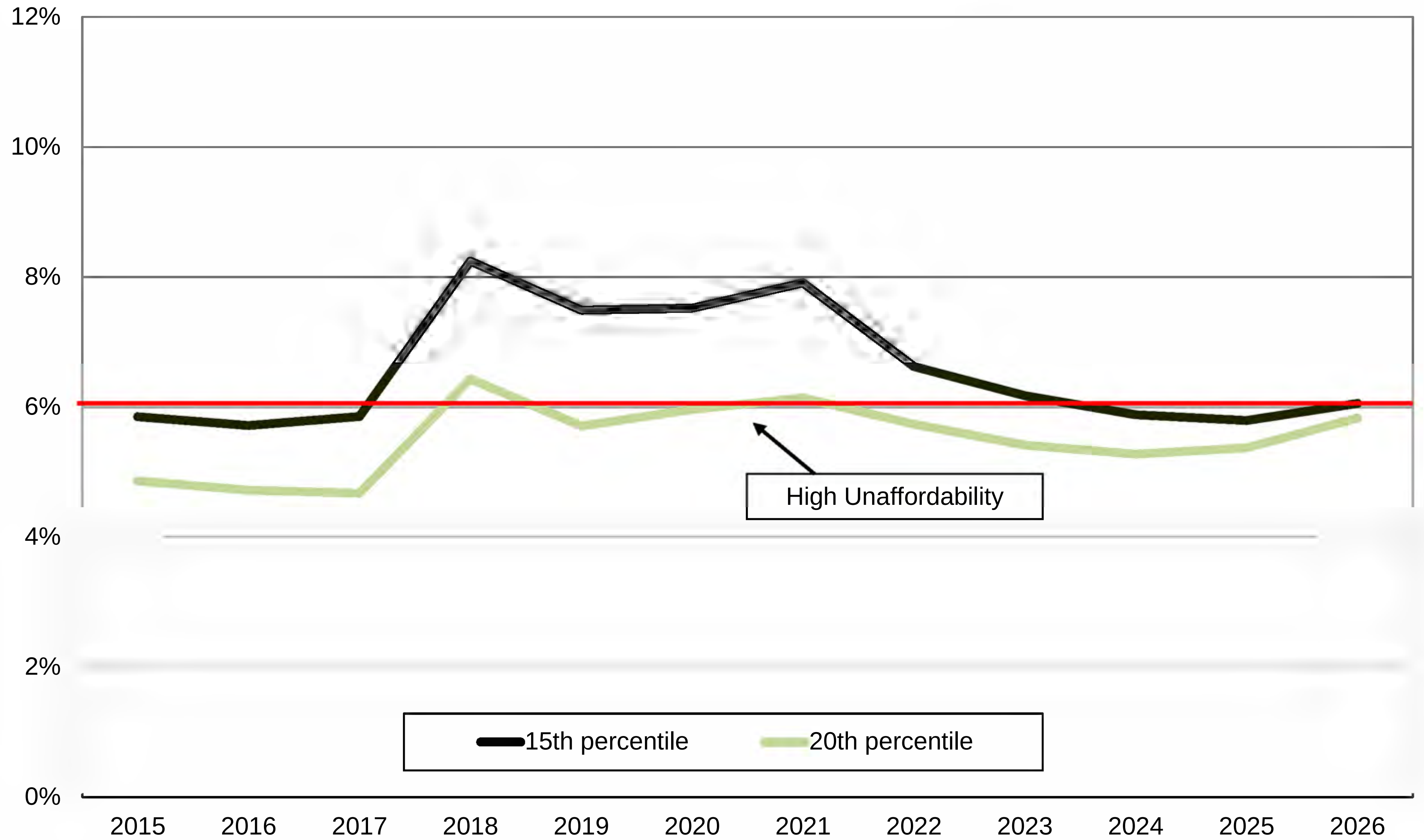
County-level CEI South Energy Affordability: Gibson County



County-level CEI South Energy Affordability: Pike County



County-level CEI South Energy Affordability: Dubois County



Comparison of Production Plant, 2018 to 2024

Unit Name	In-Service Year	Primary Fuel	Renewable (Y/N)	Gross Plant ($000)	Accumulated Reserve ($000)	Net Plant ($000)	2018 Net Plant: Net Plant ($000)	2018 Net Plant: Percent of Total (%)	2025 Net Plant: Net Plant ($000)	2025 Net Plant: Percent of Total (%)
F.B. Culley Unit 3	1973	Coal	N	$ 468,178	$ 351,836	$116,342	$116,342	85.8%	$116,342	12.0%
A.B. Brown 3	1991	Gas	N	32,929	29,546	3,384	$ 3,384	2.5%	$ 3,384	0.3%
A.B. Brown 4	2002	Gas	N	31,409	28,513	2,896	$ 2,896	2.1%	$ 2,896	0.3%
Blackfoot	2009	Landfill Gas	Y	11,703	6,842	4,862	$ 4,862	3.6%	$ 4,862	0.5%
Oak Hill Solar	2018	Solar	Y	5,372	1,557	3,814	$ 3,814	2.8%	$ 3,814	0.4%
Volkman Solar	2018	Solar	Y	7,259	2,951	4,307	$ 4,307	3.2%	$ 4,307	0.4%
Troy Solar	2021	Solar	Y	97,673	14,191	83,482	$ -	0.0%	$ 83,482	8.6%
A.B. Brown 5 &6	2025	Gas	N	339,618	4,865	334,754	$ -	0.0%	$334,754	34.4%
Posey County Solar Project	2025	Solar	Y	426,973	8,302	418,671	$ -	0.0%	$418,671	43.1%
Total Generation Plant				**$1,421,114**	**$ 448,602**	**$972,512**	**$135,605**	**100.0%**	**$972,512**	**100.0%**
Total Renewable Generation Plant				**$ 548,979**	**$ 33,844**	**$515,136**	**$ 12,983**	**9.6%**	**$515,136**	**53.0%**

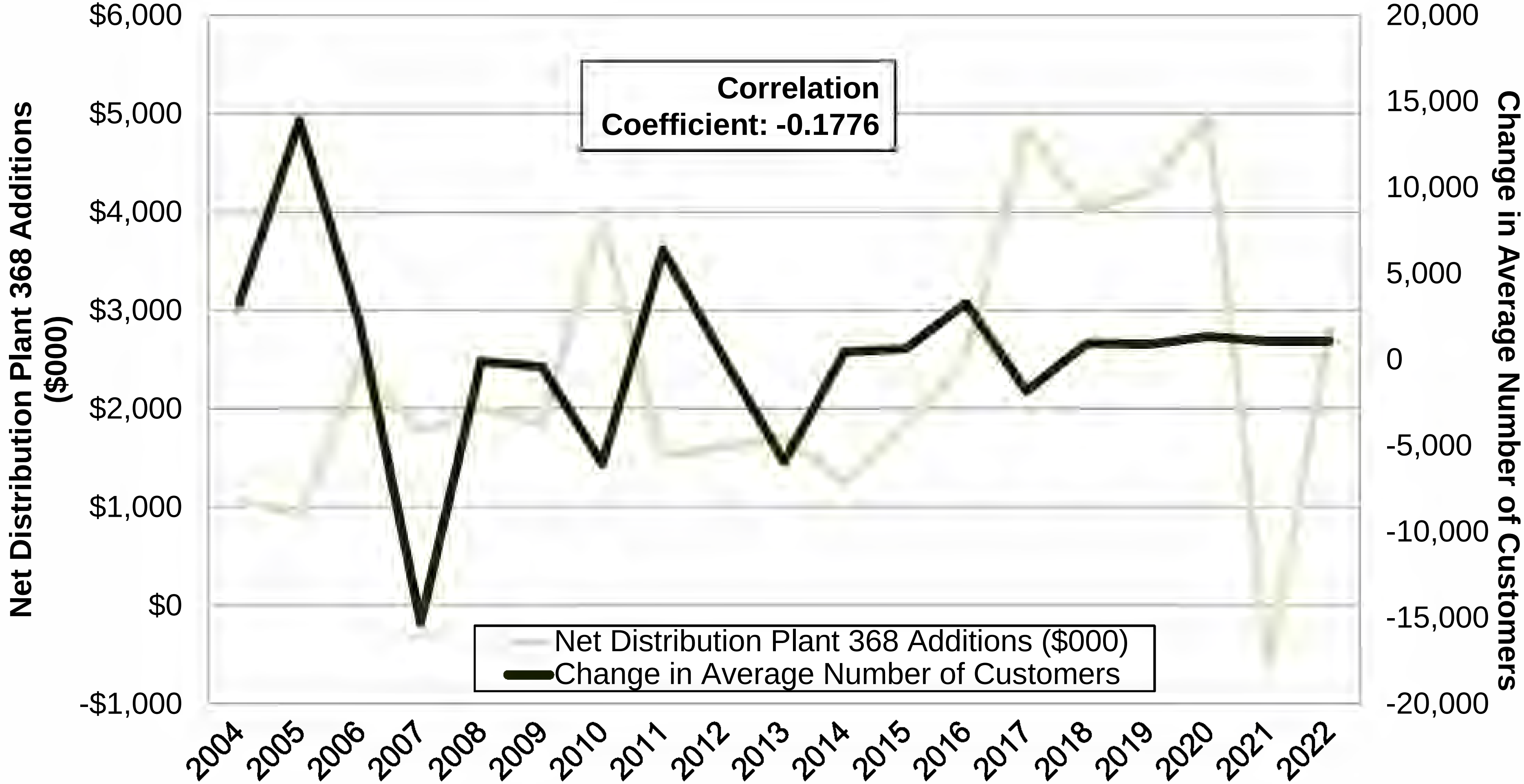
Source: Company’s Response to Data Request OUCC 18.2.

Estimated Transmission and Distribution Plant Capital Investments, 2024-2025

Investment type	Dollar Amount ($) 2024	Dollar Amount ($) 2025	Percentage (%) 2024	Percentage (%) 2025
Transmission & Distribution				
Growth	$ 5,685,704	$ 5,685,704	4%	3%
Reliability	122,326,193	155,488,907	93%	93%
Policiy	3,729,088	5,227,647	3%	3%
Total	**$ 131,740,985**	**$ 166,402,258**	**100%**	**100%**

Source: Direct Testimony of Stephen R. Rawlinson.

Correlation between Customer and Line Transformer Investments, 2004-2022.



Source: FERC Form 1.

Results of Alternative Revenue Distribution At Settlement Revenue Requirement

Witness: Dismukes
Cause No. 45990
Exhibit DED-5-S

			Residential						Lighting	
Line No.	Account Description	Total CEI South	Residential Service (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
1	**Allocated Cost of Service Study Results**									
2	Current Operating Revenues	$ 723,922,849	$ 318,179,438	$ 1,766,970	$ 14,693,952	$ 206,714,134	$ 168,795,811	$ 8,758,066	$ 1,868,087	$ 3,146,391
3	Operating Income	$ 117,233,543	$ 58,292,102	$ 30,709	$ 2,878,911	$ 39,576,293	$ 14,527,777	$ 503,350	$ 698,275	$ 726,124
4	Rate Base	$ 2,769,851,666	$ 1,263,495,769	$ 7,626,310	$ 54,308,392	$ 771,018,249	$ 624,630,809	$ 27,307,974	$ 6,754,931	$ 14,709,232
5	**Rate of Return**	**4.23%**	**4.61%**	**0.40%**	**5.30%**	**5.13%**	**2.33%**	**1.84%**	**10.34%**	**4.94%**
6	**Relative Rate of Return**	**1.00**	**1.09**	**0.10**	**1.25**	**1.21**	**0.55**	**0.44**	**2.44**	**1.17**
7	**Proposed Revenue Increase**									
8	Proposed Rate of Return	6.77%								
9	Current Operating Revenues	$ 723,922,849								
10	Proposed Operating Revenue Increase	80,009,617								
11	**Proposed Revenue Requirement**	**$ 803,932,466**								
12	**Proposed Revenue Allocation at Full Cost of Service**									
13	Current Operating Revenues	$ 723,922,849	$ 318,179,438	$ 1,766,970	$ 14,693,952	$ 206,714,134	$ 168,795,811	$ 8,758,066	$ 1,868,087	$ 3,146,391
14	Total Revenue Requirement at Equal Rates of Return	803,932,466	350,648,958	2,319,652	15,674,844	221,269,884	198,763,985	10,146,366	1,618,714	3,490,062
15	Incremental Revenue Increase at Equal Rates of Return	$ 80,009,617	$ 32,469,520	$ 552,681	$ 980,892	$ 14,555,750	$ 29,968,174	$ 1,388,301	$ (249,373)	$ 343,671
16	**Percent Increase at Proposed Rate of Return**	**11.05%**	**10.20%**	**31.28%**	**6.68%**	**7.04%**	**17.75%**	**15.85%**	**-13.35%**	**10.92%**
17	**Relative Increase**	**1.00**	**0.92**	**2.83**	**0.60**	**0.64**	**1.61**	**1.43**	**(1.21)**	**0.99**
18	**Step One Adjustments**									
19	Maximum Rate Increase at 1.15 times System Average	12.71%	-	12.71%	-	-	12.71%	12.71%	-	-
20	Step One Revenue Adjustments	$ (9,117,361)	$ -	$ (328,098)	$ -	$ -	$ (8,514,118)	$ (275,145)	$ -	$ -
21	Revenue Allocation after Step One Adjustments	$ 70,892,255	$ 32,469,520	$ 224,583	$ 980,892	$ 14,555,750	$ 21,454,056	$ 1,113,156	$ (249,373)	$ 343,671
22	Revenue Deficiency after Step One Adjustments	9,117,361								
23	**Step Two Adjustments**									
24	Minimum Rate Increase at 0.00 times System Average	0.00%	-	-	-	-	-	-	0.00%	-
25	Step Two Revenue Adjustments	249,373	$ -	$ -	$ -	$ -	$ -	$ -	$ 249,373	$ -
26	Revenue Allocation after Step Two Adjustments	$ 71,141,628	$ 32,469,520	$ 224,583	$ 980,892	$ 14,555,750	$ 21,454,056	$ 1,113,156	$ -	$ 343,671
27	Revenue Deficiency after Step Two Adjustments	$ 8,867,988								
28	**Step Three Adjustments**									
29	Basis for Step Three Adjustment	$ 542,733,916	$ 318,179,438	$ -	$ 14,693,952	$ 206,714,134	$ -	$ -	$ -	$ 3,146,391
30	Allocation of Remaining Revenue Deficiency	$ 8,867,988	$ 5,198,886	$ -	$ 240,091	$ 3,377,601	$ -	$ -	$ -	$ 51,410
31	**Total Proposed Revenue Increase**	**$ 80,009,617**	**$ 37,668,406**	**$ 224,583**	**$ 1,220,984**	**$ 17,933,351**	**$ 21,454,056**	**$ 1,113,156**	**$ -**	**$ 395,081**
32	**Summary**									
33	Current Operating Revenues	$ 723,922,849	$ 318,179,438	$ 1,766,970	$ 14,693,952	$ 206,714,134	$ 168,795,811	$ 8,758,066	$ 1,868,087	$ 3,146,391
34	Revenue Increase	80,009,617	37,668,406	224,583	1,220,984	17,933,351	21,454,056	1,113,156	-	395,081
35	**Proposed Revenue**	**$ 803,932,466**	**$ 355,847,844**	**$ 1,991,554**	**$ 15,914,936**	**$ 224,647,485**	**$ 190,249,867**	**$ 9,871,221**	**$ 1,868,087**	**$ 3,541,473**
36	**Proposed Revenue Change (%)**	**11.05%**	**11.84%**	**12.71%**	**8.31%**	**8.68%**	**12.71%**	**12.71%**	**0.00%**	**12.56%**
37	**Relative Proposed Revenue Increase**	**1.00**	**1.07**	**1.15**	**0.75**	**0.78**	**1.15**	**1.15**	**0.00**	**1.14**

CERTIFICATE OF SERVICE

This is to certify that a copy of the foregoing has been served upon the following counsel of record in the captioned proceeding by electronic service on July 19, 2024.

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