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**

PUBLIC'S EXHIBIT NO. 6

TESTIMONY OF MARGARET A. STULL

ON BEHALF OF

THE INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

March 12, 2024

Respectfully submitted,

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

Daniel M. Le Vay, Attorney No. 22184-49
Deputy Consumer Counselor
T. Jason Haas, Attorney No. 34983-29
Deputy Consumer Counselor
Adam J. Kashin, Attorney No. 37960-49
Deputy Consumer Counselor
OFFICE OF UTILITY CONSUMER COUNSELOR
115 W. Washington St. Suite 1500 South
Indianapolis, IN 46204
Email: dlevay@oucc.in.gov
thaas@oucc.in.gov
AKashin@oucc.IN.gov

CERTIFICATE OF SERVICE

This is to certify that a copy of the ***Public's Exhibit No. 6 – Testimony of Margaret A. Stull on behalf of the OUCC*** has been served upon the following in the captioned proceeding by electronic service on March 12, 2024.

Heather A. Watts
Jeffery A. Earl
Alyssa N. Allison
Kelly M. Beyrer
Matthew A. Rice
CENTERPOINT ENERGY INDIANA SOUTH
211 NW Riverside Dr.
Evansville, Indiana 47708
Email: Heather.Watts@centerpointenergy.com
Jeffery.Earl@centerpointenergy.com
Alyssa.Allison@centerpointenergy.com
Kelly.Beyrer@centerpointenergy.com
Matt.Rice@centerpointenergy.com

Tabitha Balzer
Todd Richardson
CEIS INDUSTRIAL GROUP
LEWIS & KAPPES, P.C.
One American Square, Suite 2500
Indianapolis, IN 46282
Email: tbalzer@lewis-kappes.com
trichardson@lewis-kappes.com
atyler@lewis-kappes.com
etennant@lewis-kappes.com

Common Council of the City of Evansville, IN
Anne E. Becker
Aaron A. Schmoll
LEWIS KAPPES, P.C.
One American Square, Suite 2500
Indianapolis, IN 46282-0003
Email: abecker@lewis-kappes.com
aschmoll@lewis-kappes.com

Nicholas K. Kile
Hillary J. Close
Lauren M. Box
Lauren Aguilar
BARNES & THORNBURG LLP
11 South Meridian Street
Indianapolis, Indiana 46204
Email: nicholas.kile@btlaw.com
hillary.close@btlaw.com
lauren.box@btlaw.com
lauren.aguilar@btlaw.com

Jennifer Washburn
CITIZENS ACTION COALITION OF IN, INC.
1915 West 18th Street, Suite C
Indianapolis, Indiana 46202
Email: jwashburn@citact.org
rkurtz@citact.org

Courtesy Copy:
Nikki Gray Shoultz
BOSE MCKINNEY & EVANS
111 Monument Circle, Suite 2700
Indianapolis, IN 46204
Email: Nshoultz@boselaw.com

Daniel M. Le Vay
Deputy Consumer Counselor

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
115 West Washington Street
Suite 1500 South
Indianapolis, IN 46204
infomgt@oucc.in.gov
317/232-2494 – Phone
317/232-5923 – Facsimile

TESTIMONY OF OUCC WITNESS MARGARET A. STULL

CAUSE NO. 45990

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY D/B/A CENTERPOINT ENERGY INDIANA SOUTH ("CEI SOUTH")

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Margaret A. Stull, and my business address is 115 W. Washington St., Suite 1500 South, Indianapolis, Indiana 46204.

Q: By whom are you employed and in what capacity?

A: I am employed by the Indiana Office of Utility Consumer Counselor ("OUCC") as a Chief Technical Advisor within the Water/Wastewater Division. My qualifications are set forth in Appendix A.

Q: What is the purpose of your testimony?

A: In this general rate case, Southern Indiana Gas and Electric Company D/B/A CenterPoint Energy Indiana South (hereafter "CEI South" or "Petitioner") requested (1) approval of a Tax Adjustment Rider ("TAR"); (2) approval to recover a return on any increase or decrease to its corporate alternative minimum tax carryforward occurring between rate cases; (3) implementation of a rate increase before the start of its forward-looking test year; (4) implementation of phased-in rates; and (5) implementation of rate increases *during* the forward-looking test year to reflect projected rate base additions. The purpose of my testimony is to support the following recommendations I make in response to those requests:

(1) Acceptance of the creation of a tax adjustment rider through which all currently approved and future tax related tracker mechanisms will be recovered.

(2) Denial of Petitioner's proposed tracker providing a return on any increase or decrease in its corporate alternative minimum tax carryforward that occurs between rate cases. In the alternative, if Petitioner is authorized this treatment, I recommend Petitioner be required to track <u>all</u> tax related components of cost-free capital, not just the components that benefit Petitioner.

(3) Denial of Petitioner's proposed implementation of a rate increase prior to the start of its forward-looking test year.

(4) Acceptance of Petitioner's proposed process for implementing rates at the beginning of the forward-looking test year and at the end of the forward-looking test year with some modifications.

(5) Denial of Petitioner's proposal to implement rate increases *during* the forward-looking test year (2025).

I also discuss Petitioner's presentation of its accounting schedules and revenue requirement noting the lack of evidence provided to support its request.

Q: If you do not address a specific item or adjustment, should that be construed to mean you agree with Petitioner's proposal?

A: No. Not addressing a specific item or adjustment Petitioner proposes does not indicate my agreement or approval. Rather, my opinions are limited to my explicit statements addressing the specific items I address in this testimony.

Q: Please describe the review and analysis you performed.

A: I read Petitioner's case-in-chief testimony related to the topics addressed in my testimony. I reviewed Petitioner's related schedules and workpapers, including Exhibit No. 20 and MSFR workpapers. I reviewed Petitioner's 2022 FERC Form 1 and the filings in Cause Nos. 45447 (CEI South Gas Order, October 30, 2020) and 45468 (CEI North Gas Order, December 18, 2020). I prepared discovery questions and reviewed Petitioner's responses; and I followed up to procure more complete information when the responses did not provide the information requested.

Q: Do you sponsor any attachments?

A: Yes. I sponsor the following attachments:

- **<u>Attachment MAS-1</u>** – Petitioner's response to OUCC Data Request No. 7-13 regarding State EADIT regulatory liability balance (PDF and Excel).
- **<u>Attachment MAS-2</u>** – Petitioner's Calculation of Phase 2 Federal Income Tax Expense, Attachment CMB-5.
- **<u>Attachment MAS-3</u>** – CenterPoint news releases regarding asset sales announced in February 2020, April 2021, and February 2024.
- **<u>Attachment MAS-4</u>** – Wall Street Journal article dated March 30, 2023 regarding CenterPoint Energy's corporate alternative minimum tax predicament.
- **<u>Attachment MAS-5</u>** – New York Times article dated September 7, 2023 regarding CenterPoint Energy's corporate alternative minimum tax situation.
- **<u>Attachment MAS-6</u>** – Petitioner's response to OUCC Data Request No. 3-13 regarding Petitioner's Phase 1 rate proposal.
- **<u>Attachment MAS-7</u>** – Petitioner's response to OUCC Data Request No. 30-11 regarding Petitioner's Phase 1 rate proposal.
- **<u>Attachment MAS-8</u>** – Petitioner's response to OUCC Data Request No. 30-6 regarding "Unadjusted Test Year."

II. <u>TAX ADJUSTMENT RIDER ("TAR")</u>

Q: Please explain Petitioner's proposed Tax Adjustment Rider ("TAR") and what costs it proposes to recover or pass back through this new rider.

A: Petitioner's witness Jennifer K. Story explained that the purpose of the tax adjustment rider is to put all tax related trackers and recovery mechanisms into one rider. Petitioner's proposed rider would capture tax rider adjustments already approved by the Commission in other dockets and add two new tax riders to (1) pass back *state* excess accumulated deferred income taxes ("EADIT"), and (2) address the potential effects of the corporate alternative minimum tax ("CAMT") on Petitioner's cash flow from operations.

A. Approved Tax Adjustment Mechanisms

Q: What existing tax adjustment mechanisms will be moved to the tax adjustment rider?

A: Ms. Story explained there are two already approved tax mechanisms that would move to the tax adjustment rider. The first of these is the pass back of *federal* EADIT resulting from the Tax Cuts and Jobs Act ("TCJA"), which is currently being recovered through Petitioner's Transmission, Distribution, and Storage System Improvement Charge ("TDSIC").[1] The second already approved tax mechanism is related to production tax credits ("PTC") "realized from approved wind and solar projects…to be tracked through Petitioner's Clean Energy Cost Adjustment ("CECA") mechanism." (Story at p. 11, lines 8-9.)

Q: Do you accept Petitioner's proposal to move existing tax adjustment mechanisms to its proposed tax adjustment rider?

A: Yes. As these tax recovery mechanisms have already been approved, it is reasonable to include all tax related recovery and pass back mechanisms under one rider as a matter of administrative efficiency.

[1] Federal EADIT will continue to be passed back to customers outside of base rates after moving to the tax adjustment rider.

Q: Are there any qualifications to your acceptance of this proposal?

A: Yes. The OUCC accepts this proposal with the understanding that the current tax mechanisms will continue to charge or credit the same customer classes in the same manner as they are currently being implemented.

A. State Excess Deferred Income Taxes ("EADIT")[2]

Q: Please explain how State excess accumulated deferred income taxes were generated.

A: State EADIT was primarily generated due to gradual reductions to the Indiana corporate income tax rates from July 2012 through July 2021. The Indiana corporate income tax rate decreased from 8.5% in June 2012 to 4.9% in July 2021. As a result of these rate decreases, Petitioner was required to remeasure its state accumulated deferred income tax balances ("ADIT") to reflect the current tax rates in effect. That remeasurement created a tax regulatory liability that is owed to Petitioner's ratepayers.[3] Petitioner will begin crediting customers upon the issuance of an order in this Cause.

Q: What is the current balance of Petitioner's State EADIT balance to be returned to Petitioner's electric ratepayers?

A: According to Petitioner's case-in-chief, the balance of its state EADIT tax regulatory liability at 12/31/2022 was $11,412,319.[4] (See Story at p. 12, line 23.) Petitioner did not forecast any changes to this balance through the end of its

[2] This state EADIT is separate and distinct from the federal EADIT created by the Tax Cuts and Jobs Act of 2017 and which Petitioner is currently crediting customers through its TDSIC tracker mechanism.

[3] Customer rates included state income tax at the 8.5% tax rate. Therefore, when state tax rates declined, ratepayers were due a refund of these excess accumulated deferred income taxes.

[4] Account 257040; FERC Account 254.0 – See Exhibit No. 20, Workpaper D-5.1, cell G41.

forward-looking test period, so this is also the balance included in the cost-free capital component of Petitioner's December 31, 2025 capital structure.

Q: How long does Petitioner propose to refund these excess accumulated deferred income taxes to its customers?

A: Petitioner proposes to refund State excess accumulated deferred income taxes to its customers over a five-year period beginning when an order is issued in this Cause.

Q: Will the refund of state EADIT be "outside base rates," like the current treatment of federal EADIT?

A: Yes. Petitioner proposes state EADIT would also be amortized outside base rates.

Q: Does Petitioner propose its tax adjustment rider would address future changes to its Federal and State EADIT balances?

A: Yes. Petitioner proposes any future changes to federal or state EADIT balances would be addressed through the tax adjustment rider.

Q: Do you agree with Petitioner's proposal regarding the pass back of State excess accumulated deferred income taxes?

A: No. I do not agree with Petitioner's proposed amortization period. Also, carrying costs should be included in the amount to be refunded to customers because Petitioner has owed some refund to customers since 2011. This liability has grown to $11,412,319 according to the detailed calculation Petitioner provided (OUCC Attachment MAS-1):

Table 1: Regulatory Tax Liability Balance by Year

Balance as of 12/31/2011	(5,100,270)
Balance as of 12/31/2012	(4,571,099)
Balance as of 12/31/2013	(2,068,320)
Balance as of 12/31/2014	(4,122,083)
Balance as of 12/31/2015	(7,830,290)
Balance as of 12/31/2016	(9,212,117)
Balance as of 12/31/2017	(9,141,521)
Balance as of 12/31/2018	(5,083,699)
Balance as of 12/31/2019	(5,772,648)
Balance as of 12/31/2020	(7,073,900)
Balance as of 12/31/2021	(10,730,592)
Balance as of 12/31/2022	(11,412,314)

Petitioner will have owed a liability for approximately 14 years when it begins providing refunds to customers in late 2024 or early 2025, when an order is expected in this Cause. Petitioner expects and requests carrying charges be included in costs it invests during both the construction period as well as the post-construction period before an asset is included in rate base. Because of the delay in implementing this refund, customers have been deprived the use of money that has subsequently been devalued by inflation. It is reasonable and equitable that customers also be compensated for the time value of money when Petitioner has owed a liability to them.

Q: What do you recommend for the pass back of State EADIT?

A: I recommend Petitioner refund its state EADIT tax regulatory liability to customers within three years. The refund should include cumulative carrying charges calculated using Petitioner's weighted average cost of capital in each year it has owed this liability. I also recommend Petitioner be required to submit a post-order compliance filing within three months of the date a final order is issued in this case showing (1) the growth of this liability by year from 2011 to the date Petitioner begins refunding this liability and (2) the detailed calculation of the carrying costs included in the amount to be refunded. Petitioner should also make a compliance filing once all monies are refunded to customers, certifying that all monies owed to customers have been paid and indicating the amount refunded to customers in each year.

B. Inflation Reduction Act

1. Summary of Inflation Reduction Act Provisions

Q: What utility tax related advantages and disadvantages are included in the Inflation Reduction Act?

A: The primary purpose of the Inflation Reduction Act was to fight inflation through deficit reductions and to advance climate initiatives. To encourage investments in clean energy and renewable investments, the Inflation Reduction Act restores and extends renewable electricity production tax credits and clean electricity investment tax credits. It also creates new tax credits designed to incent investment in renewable energy. However, to pay for the tax credit benefits, the Inflation Reduction Act imposes a new 15% corporate alternative minimum tax ("CAMT").

2. Corporate Alternative Minimum Tax

Q: How is the corporate alternative minimum tax calculated or determined?

A: Corporate alternative minimum tax due is equal to 15% of an entity's adjusted financial statement income ("AFSI"). Adjusted financial statement income is equal to the taxpayer's book income (or loss) prepared in accordance with US generally accepted accounting principles with certain limited adjustments, including tax depreciation in lieu of book depreciation.

Q: How is the corporate alternative minimum tax being implemented?

A: Companies will now generally <u>pay</u> tax equal to the greater of 15% of Adjusted Financial Statement Income or their regular federal tax liability. However, the corporate alternative minimum tax does not increase a company's federal income tax <u>expense</u>. It just shifts income taxes that otherwise would be deferred to current.

Q: Does Petitioner expect to pay the corporate alternative minimum tax in 2023, 2024 or 2025?

A: Yes. Ms. Story testified Petitioner will not owe corporate alternative minimum tax in 2023 because Petitioner expects to pay regular income tax in excess of the corporate alternative minimum tax. However, Ms. Story indicated Petitioner expects to pay corporate alternative minimum tax in 2024 and 2025 (Story at p. 9, lines 11-12). According to Exhibit No. 20, Schedule C-5, in 2025 Petitioner has forecasted a corporate alternative minimum tax of $31,234,107 (cell L97) and a regular tax of $11,880,564 (cell L83). This yields a corporate alternative minimum tax <u>payment</u> of $19,353,543 ($31,234,107 - $11,880,564). In 2024, Petitioner forecasted a corporate alternative minimum tax of $19,947,956 and a regular tax of $(532,508). This yields a corporate alternative minimum tax payment of $20,480,464 ($19,947,956 + $532,508). (OUCC Attachment MAS-2).[5]

Q: Are corporate alternative minimum tax payments creditable against future federal income taxes?

A: Yes. The payment of corporate alternative minimum taxes generates a carryforward that can be credited against future federal income tax liabilities, at least to the extent the regular income tax liability exceeds the corporate alternative minimum tax liability in a given tax year. This carryforward is a deferred tax asset included in Petitioner's capital structure as a reduction to cost-free capital. These credits can be carried forward indefinitely.

3. Tax Adjustment Rider ("TAR")

Q: What elements of the Inflation Reduction Act does Petitioner propose to track in its proposed tax adjustment rider?

A: Petitioner proposes to track the new production tax credits and investment tax credits created by the Inflation Reduction Act. Also, between rate cases, Petitioner proposes to recover a *return on* the balance of its corporate alternative minimum tax carryforward through its proposed tax adjustment rider. This return would be calculated using Petitioner's weighted average cost of capital determined in this rate case.

[5] In response to OUCC Data Request No. 6-1, Petitioner provided its Phase 2 forecasting model, which included the federal income tax calculation provided in OUCC Attachment MAS-2.

Q: When will Petitioner begin tracking the production tax credits?

A: Petitioner proposes the tracking for production tax credits would begin in 2025. If approved, Petitioner will file a tax adjustment rider in November 2024 that will include an estimate of the 2025 production tax credits. Thereafter, subsequent annual tax adjustment rider filings will include estimates of the following year's production tax credits and a true-up of the prior year's production tax credits to actual.

Q: When does Petitioner anticipate recovery of a return on the balance of its corporate alternative minimum tax carryforward will begin?

A: Petitioner proposes the recovery of a return on the balance of its corporate alternative minimum tax carryforward would begin in 2026, which is after the end of the test period. According to Petitioner, the tax adjustment rider filing in November 2026 will include the difference between the estimated balance of the 2026 alternative minimum tax carryforward and the carryforward balance included in cost free capital in base rates as of December 31, 2025. The difference between these two balances will be multiplied by the approved cost of capital from this proceeding.

Q: Why does Petitioner say it should recover a *return on* the balance of its corporate alternative minimum tax carryforward?

A: Petitioner's witness Brett A. Jerasa discussed the effect these corporate alternative minimum tax payments could have on its cash flow from operations and its credit metrics (Jerasa at pages 7–8). Mr. Jerasa testified "the cash outlay associated with CAMT presents a risk that will likely adversely impact CEI South's credit metrics including Funds From Operations ("FFO")/debt if we are unable to recover the impact of the tax through rates." (Jerasa Direct at page 7, lines 17-20.)

Q: Does the table on page 7 of Mr. Jerasa's testimony accurately reflect Petitioner's proposal regarding corporate alternative minimum taxes?

A: No. Table BAJ-1 purports to compare the impact of the corporate alternative minimum tax on funds from operations, with and without the recovery of corporate alternative minimum tax as proposed by Petitioner. First, Mr. Jerasa's table misstates Petitioner's proposal in this case, indicating, inaccurately, that its rate base would be adjusted if its proposed recovery of the corporate alternative minimum tax is authorized. That is not what Petitioner has proposed or reflected in its schedules, at least as described by Ms. Story (Story at p. 11). Petitioner proposed a tax rider be authorized to recover a return on the balance of its corporate alternative minimum tax carryforward. This carryforward is a deferred tax asset that Petitioner included in its capital structure as a reduction to tis *cost-free* source of capital. Petitioner has *not* proposed to recover the tax payment itself or include the regulatory asset in rate base. Rate base will *not* be increased if it is authorized to recover its proposed corporate alternative minimum tax.

Second, and more importantly, Mr. Jerasa's table significantly overstates the effect Petitioner's proposal will have on its funds from operations. Table BAJ-1 assumes a dollar-for-dollar recovery of the corporate alternative minimum tax payment. In the column that represents cash flow "with recovery," the increase to net income equals the corporate alternative minimum tax payment. This does not reflect how the cash flows from Petitioner's proposed tax adjustment rider would work. Petitioner has proposed to only recover a return on these payments, not recovery of the payments themselves. To illustrate, assume there is a $1,000 payment or cash outflow. The return on that $1,000 payment that would be recovered through the proposed tax adjustment rider would be approximately 7.0%[6], yielding an associated cash inflow of $70. Therefore, Petitioner's proposal would not materially alleviate any effect the corporate alternative minimum tax would have on its funds from operations.

Q: Do you accept Petitioner's proposal to recover a return on the balance of its corporate alternative minimum tax carryforward?

A: No. A taxpayer is *only* subject to the alternative minimum tax if it has average adjusted financial statement income ("AFSI") of $1.0 billion over the most recent three-year period. Importantly, Petitioner's parent company, CenterPoint Energy[7], does not normally have AFSI of $1.0 billion or more. Center Point Energy is only currently subject to the corporate alternative minimum tax because of the impact of recent utility asset sales in other jurisdictions. Otherwise, Petitioner's parent company would not be subject to the corporate alternative minimum tax.

Q: Please identify the utility asset sales Petitioner's parent company CenterPoint Energy has recently completed or announced.

A: On April 29, 2021, CenterPoint Energy entered into an asset purchase agreement to sell its Arkansas and Oklahoma natural gas businesses for $2.15 billion in cash, including recovery of approximately $425 million in natural gas costs. This

[6] The weighted average cost of capital proposed by Petitioner in this case is 7.06%.

[7] Petitioner's parent company files a consolidated tax return and will be the taxpayer that will be assessed the corporate alternative minimum tax.

transaction closed on January 10, 2022. On February 20, 2024, CenterPoint Energy announced the sale of its Louisiana and Mississippi natural gas assets for $1.2 billion. This sale is expected to close toward the end of the first quarter of 2025. On February 24, 2024, CenterPoint Energy announced the sale of its natural gas retail business for approximately $400 million. (See OUCC Attachment MAS-3.)

Q: Did you find any articles discussing CenterPoint Energy's alternative minimum tax situation?

A: Yes. A 2023 Wall Street Journal article quoted CenterPoint Energy acknowledging that its recent pattern of selling utility assets has increased the likelihood of it becoming subject to the corporate alternative minimum tax. (OUCC Attachment MAS-4):

> Electric and natural-gas utility CenterPoint, meanwhile, sold two businesses during the three-year period used to determine the applicability of the minimum tax, from 2020 through 2022. These sales produced substantial book and tax gains—which CenterPoint paid regular corporate income tax on—that would likely subject the company to the minimum tax, CenterPoint said in a March 15 comment. [8]

In 2023, CenterPoint Energy also sent a comment letter to the Treasury Department and the Internal Revenue Service arguing it could be "unfairly targeted because it had sold part of its gas pipeline and storage operation." Even

---

[8] Williams-Alvarez, Jennifer. "New Corporate Minimum Tax Could Ensnare Some Firms over One-Time Moves" *Wall Street Journal*, 30 Mar. 2023, www.wsj.com/articles/new-corporate-minimum-tax-could-ensnare-some-firms-over-one-time-moves-260f74df.

though CenterPoint Energy paid taxes on the sale, the gains could raise the company's revenue enough to require it to pay additional money under the corporate alternative minimum tax (OUCC Attachment MAS-5). The company wrote:

> CenterPoint is neither a large corporation nor a corporation that did not pay its fair share [of income taxes] but is being subjected to the C.A.M.T. as a result of transactions that reduced its business operations. The incongruity of the result is striking." [9]

Q: Do you have any other concerns regarding Petitioner's proposal?

A: Yes. Petitioner is "cherry picking." Petitioner proposes to track one component of its cost-free capital that tends to increase its rates, while ignoring all components where tracking would benefit ratepayers with a rate reduction. These latter components include accumulated deferred income taxes. Essentially, the corporate alternative minimum tax shifts deferred federal income taxes to current, which reduces accumulated deferred income taxes. Petitioner proposes to track this *reduction* to accumulated deferred income taxes but not any *increases* to accumulated deferred income taxes during the same time-period. Such increases could occur due to the difference between book and tax depreciation expense. If certain elements of cost-free capital are to be tracked between rate cases, it is only reasonable if the utility is required to track all tax related components of cost-free capital, not just the ones where tracking the component would benefit the utility.

---

[9] Rappeport, Alan. "New Corporate Minimum Tax Ushers in Confusion and a Lobbying Blitz" *New York Times,* 7 September 2023, www.nytimes.com/2023/09/07/business/corporate-minimum-tax-impact.html.

Q: If the U.S. Treasury Department determines Petitioner's parent company is subject to the corporate alternative minimum tax, should those taxes be borne by Indiana rate payers?

A: No. Indiana ratepayers should not bear the costs of CenterPoint Energy's non-Indiana financial transactions, including any additional taxes that may be due because of those transactions.

Q: What do you recommend regarding Petitioner's proposal to earn a return on the increase (or decrease) to the balance of its corporate alternative minimum tax carryforward between rate cases?

A: Many unknowns accompany Petitioner's proposal, including not knowing whether Petitioner's parent company will even be subject to the corporate alternative minimum tax. Also unknown is whether Petitioner's proposal would materially ameliorate the resulting effects to its credit metrics or ratings. Consequently, Petitioner has not established that the relief is needed or that it will benefit its financial condition if it is needed. Further, even if Petitioner's parent company is subject to the corporate alternative minimum tax, it is not reasonable for Indiana ratepayers to bear any added costs related to its parent company's activities. I recommend Petitioner's proposal be denied. However, if the Commission were to nonetheless find Petitioner's proposal should be authorized, I would recommend Petitioner also be *required* to track all tax related components of cost-free capital.

III. IMPLEMENTATION OF RATES PRIOR TO THE START OF THE FORWARD-LOOKING TEST YEAR

Q: How does Petitioner propose to implement its proposed rate increase?

A: Petitioner proposes its rates be implemented over three main phases (Behme at page 6, lines 24-25). Petitioner proposes to implement its Phase 1 rate increase when the order is issued in this Cause, which is expected in early October 2024 and is roughly three months before the start of its forward-looking test year (January 2025 – December 2025). Petitioner's witness Chrissy M. Behme testified Phase 1 rates will be based on actual rate base and capital structure as of December 31, 2023, and *Pro forma* net income will be based on forecasted revenues and operating expenses "updated to November 2024" (Behme at p 6).

Q: What does Ms. Behme mean by the phrase "updated to November 2024"?

A: In response to discovery, Petitioner stated that Ms. Behme is referring to a 12-month period beginning with November 2024 for operating expenses only. Petitioner added that it proposes to use operating revenues for January through December 2025, with all other expenses presented at January through December 2025. *Pro forma* depreciation expense is reflected for assets placed in service through December 2023 and *pro forma* property tax expense is based on assets placed in service through December 2025. (OUCC Attachment MAS-6.)

Q: Did Petitioner further explain its proposal in its discovery response?

A: Yes. Petitioner added that *pro forma* operating net income presented for Phase 1 includes a "mixture" of two 12-month periods. Operating expense is a 12-month period for November 2024 through October 2025 with "all other activity held at January through December 2025." (OUCC Attachment MAS-6.)

Q: Why does Petitioner include forecasted test year operating revenues and expenses in Phase 1?

A: In response to discovery, Petitioner stated that "Because Phase 1 begins with November 2024. There's only two months of difference from the test yar." (OUCC Attachment MAS-7).

Q: Did Petitioner explain the basis for its proposal to implement rates prior to the start of its future test year?

A: Yes. On page 7, lines 12-13 of her testimony, Ms. Behme stated Petitioner's proposal is "modeled after the approach proposed by Indiana American Water Company in Cause No. 45870.

Q: Do you accept Petitioner's proposal to begin implementing its proposed rate increase prior to the start of its forward-looking test year?

A: No. Petitioner's proposal differs materially from the two proposals the Commission considered when it previously allowed rates to be implemented prior to the start of a utility's forward-looking test year. Moreover, Petitioner has not provided sufficient evidence or support for the Commission to approve its proposed Phase 1 pre-test year rates.

Q: How does Petitioner's proposal differ from the pre-test year rates previously approved by the Commission's prior orders?

A: In those prior orders, the basis for initial rates was a 12-month period ending approximately when an order was expected to be issued in the case. In the case of Evansville Municipal Water, Cause No. 45545, the forward-looking test period began on April 1, 2023 and Phase 1(initial) rates were based on *pro forma* net operating income for the 12-month period ending March 31, 2022.[10] A final order was issued on March 2, 2022 in that case. Similarly, in Cause No. 45870, Indiana American Water Company proposed a forward-looking test year which would begin May 1, 2024 and the Phase 1 (initial) rates were based on rate base and capital structure as of July 31, 2023 and *pro forma* net operating income for the 12-month period ending December 31, 2023. A final order was issued on February 14, 2024 in that case.

In both of those cases the utility did not seek to recover costs before they were projected to be incurred and their initial rate increase only reflected the effects of projected data through the date an order was expected to be issued. But in this case, Petitioner has proposed that Phase 1 rates be based on a 12-month period that <u>begins</u> when an order is expected to be issued, effectively seeking to recover costs before they are projected to be incurred.

Q: What do Indiana Statutes allow?

A: Indiana Code 8-1-2-42.7 establishes that rates may be based on a twelve-month forward-looking test period. Petitioner is effectively trying to base rates on more than twelve months of forward-looking data. Pursuant to subsection (d), "the commission shall approve a test period that is one of the following: . . . a forward-looking test period determined on the basis of projected data for the twelve (12) month period beginning not later than twenty-four (24) months after the date on

[10] Because Evansville is a municipal utility, it does not earn a return on rate base and, therefore, no measurement date for rate base or capital structure was established.

which the utility petitions the commission for a change in its basic rates and charges." Just as there is no provision in the statute for using projected data based on a fourteen (14) month test period (November 2024 – December 2025), there is no provision for setting rates using an additional (overlapping) twelve (12) months of projected data as Petitioner has proposed (Proposed Phase 1 ending October 2024). This is an unprecedented overreach of the statutory authorization under IC 8-1-2-42.7. In order to have the statutory benefit of a forward-looking test year and an expedited 300-day review, Petitioner should be held to the confines of the statute.

Moreover, these additional phases make forward-looking test year cases more burdensome and unwieldly for the consumer parties, which belies the expedited rate order process created by Indiana Code 8-1-2-42.7. While the proposed Phase 1 increase would only be effective for an anticipated two months, that does not eliminate the review that was necessary to evaluate that pre-authorized test year increase. Petitioner seems to be ordering an appetizer before the main course. But an appetizer is not on the statutory menu.

Q: Did Petitioner provide the information necessary to determine the projected *pro forma* operating net income for the 12-month period ended October 2024?

A: No. Even if the Commission felt it was appropriate to implement a pre-test year phase in the same manner as has previously been authorized, Petitioner did not provide any monthly data reflecting its projected *pro forma* operating net income for the linking period. For instance, Petitioner's Attachments CMB-4 and CMB-5 provide cumulative *pro forma* operating net income for its proposed Phase 1 and

Phase 2 rates but does not provide this information on a monthly basis. Further, those attachments, as filed, consist only of hard-coded cell entries and do not reveal any information showing how those amounts were determined or even how they were calculated.

Q: What do you recommend regarding the determination of Phase 1 rates in this Cause?

A: I recommend the Commission deny Petitioner's proposal to implement a rate increase before the start of Petitioner's forward-looking test year in this case. Petitioner's proposal must be viewed as either (1) the use of two overlapping 12-month projected periods on which rates will be based or (2) what amounts to the use of a 14-month projected test period (November 2024 through December 2025). In either view, Petitioner's proposal does not meet the requirements of Indiana Code 8-1-2-42.7, which allows only one 12-month projected test period.

Petitioner's case-in-chief does not include sufficient evidence or support to determine what Phase 1 rates would be if based on a 12-month period ending when an order is expected to be issued in this case. The provision of sufficient evidence and support for its projections, both during the linking period as well as the forward-looking test year, is Petitioner's burden and one which Petitioner failed to meet.

IV. PROCESS TO IMPLEMENT RATE INCREASE

C. Petitioner's Proposal

Q: What process does Petitioner suggest to implement its proposed Phase 1 rate increase?

A: Petitioner proposes Phase 1 take effect as soon as possible following the issuance of an order in this Cause and Petitioner's submission of the tariff and any required compliance filing. Petitioner proposes actual rate base and capital structure data would be submitted at the time Petitioner files its rebuttal case. Petitioner considers there is no need to build in a post order review process for Phase 1 as all information, other than the findings, that are necessary to calculate Phase 1 rates will be available before the evidentiary hearing. I would disagree that there should be no post order review process or that it is appropriate for Petitioner to supplement its case in this manner. While the OUCC considers Petitioner's proposed Phase I increase to be contrary to statute and not supported by the evidence, I address defects in Petitioner's proposed process for its requested Phase 1 at the end of this Subsection B, below.

Q: What process does Petitioner suggest to implement its proposed Phase 2?

A: Petitioner proposes Phase 2 rates be implemented as soon as possible after January 1, 2025. Petitioner would submit its compliance filing that certifies the net original cost rate base and capital structure as of December 31, 2024 and calculates the Phase 2 rates using those certified figures. Phase 2 rates would be subject to refund during the review period in the event the Commission determines that less than the certified amount of plant additions was placed in service as of December 31, 2024. Petitioner would submit its compliance filing to all parties, who would then have no more than 60 days to verify or state any objection to the net plant in service numbers Petitioner would have certified in its compliance filing. If necessary, a hearing would be convened to resolve any objections and rates would be trued up, with carrying charges at the weighted average cost of capital, retroactive to the date Phase 2 rates were submitted. (Behme at page 8, lines 1-14.)

Q: What process does Petitioner suggest to implement its proposed Phase 3 rate increase?

A: Petitioner proposes the same process as with Phase 2, except using the end of the test year rate base and capital structure (*Id*., lines 25-26).

D. <u>OUCC's Recommendation</u>

Q: Should the authorized increase to total rate base be limited to the forecasted amount?

A: Yes. In each phase, total rate base should not exceed the value of rate base as of the end of the forward-looking test year approved by the Commission in the final order. To the extent the actual value of rate base exceeds approved rate base as of December 31, 2025, the difference should be removed from actual rate base for purposes of determining the rates to be implemented in each phase. Any amounts invested in excess of the cap are eligible for inclusion in other rate or tracker proceedings.

Q: Are any adjustments to *pro forma* net operating income necessary when implementing rates in forward-looking test year cases?

A: Generally, no. But there is one situation when adjustments to *pro forma* net operating income are warranted. When a utility does not actually invest what it forecasted it would invest in rate base, adjustments to depreciation expense and property tax expense may be warranted, along with associated adjustments to income tax expense. These adjustments are necessary to prevent a utility from recovering property taxes and depreciation expense related to projected investments it did not ultimately make within the test year.

Q: Do you have any other recommendation regarding the implementation of rates?

A: Yes. In its February 14, 2024 Final Order in Cause No. 45870, the Commission discussed the complex issues presented in that case involving rates, cost of service, and rate design. Thus, to verify and ensure compliance with the Commission's findings in that order, the Commission included an additional condition that a technical conference may be convened as needed for Petitioner to explain its compliance filing. Given the difficulties the parties have had in understanding and reviewing Petitioner's case-in-chief filing and the many complex issues dealt with in this case, I recommend a similar process be implemented in this case as well. This technical conference may be held at the request of any party or the Commission staff to allow further discussion in determining whether the compliance filing complies with the order and determine what additional information should be provided in each phase.

Q: What do you recommend regarding the implementation of Phase 2 rates?

A: I recommend Phase 2 rates be implemented no sooner than January 1, 2025. Otherwise, I recommend the same compliance filing and process as discussed below for Phase 1 except items (2) through (6) should be measured as of December 31, 2024.

Q: What do you recommend regarding the implementation of Phase 3 rates?

A: I recommend Phase 3 rates be implemented no sooner than January 1, 2026. Otherwise, I recommend the same compliance filing and process as discussed below for Phase 1 except items (2) through (6) are measured as of December 31, 2025.

Q: Is Petitioner's proposed Phase 1 Implementation proposal reasonable?

A: No. As I discussed above, the proposed Phase 1 implementation is inconsistent with IC 8-1-2-42.7. Moreover, I discussed that such a Phase 1 increase is not consistent with the evidence presented by Petitioner as there is a lack of verifiable proof to support the pre-test year increase. But even if section 42.7 allowed a Phase 1 as Petitioner has proposed it and Petitioner had provided the underlying support, Petitioner's proposal (i.e., to provide updated rate base and capital structure data with its rebuttal filing) is not reasonable. First, there is no need to provide this information this early in the process as there would be no material delay in implementing any Phase 1 rates approved once an order is issued. Second, the OUCC and other intervenors will be engaged in reviewing rebuttal testimony, writing discovery and reviewing discovery responses, preparing cross questions for the hearing, and preparing themselves to be cross-examined. There is no reasonable or practicable opportunity during the three-week period between the filing of Petitioner's rebuttal and the start of the evidentiary hearing for the consumer parties to focus on reviewing a Phase 1 compliance filing. Moreover, there is no authorized process or time to respond to that additional evidence. Petitioner's proposal would deny the consumer parties their right to due process. Finally, Petitioner supplementing its case-in-chief at that time is inconsistent with the process agreed to by the parties and entered as a docket entry in this proceeding.

Q: What do you recommend regarding any implementation of Phase 1 rates?

A: A Phase 1 increase should be subject to the same process as the other phased increases. If the Commission were to allow a Phase 1 increase, Petitioner should be required to make a compliance filing to be submitted no sooner than the issuance of an order in this Cause.[11] Rates would go into effect upon the approval of the tariff and submission of the compliance filing, subject to the rights of parties to submit an objection. These rates would effectively be implemented on an interim basis subject to refund. The OUCC and other parties in such a case should have no more than 60 days to review the compliance filing and submit any objections. If necessary, a hearing would be scheduled to resolve any objections and make any needed factual findings. All supporting schedules should be

[11] The compliance filing Petitioner intends to submit with its rebuttal filing could be considered this compliance filing to the extent it provides all the information required. However, the review process for this filing would not begin until Petitioner either states it is using its previously provided submission as its compliance filing or submits a compliance filing after the issuance of an order.

submitted in Excel format with formulas intact. Such a compliance filing should also include the following:

(1) Certification of Petitioner's actual utility plant in service and actual capital structure.

(2) Actual rate base by component as of December 31, 2023, in a similar format to that of Exhibit No. 20, Schedule B-1.1 and comparing actuals to Petiitoner's Phase 1 forecast. Any variances between actuals and the Phase 1 forecast greater than 10% should be explained.

(3) Actual utility plant in service balances by FERC Account as of December 31, 2023 similar to Exhibit No. 20, Schedule B-2.1.

(4) Actual accumulated depreciation balances by FERC Account as of December 31, 2023 similar to Exhibit No. 20, Schedule B-3.1.

(5) Actual capital structure by component as of December 31, 2023, in a format similar to that of Exhibit No. 20, Schedule D-1.1, including an updated calculation of weighted average cost of capital and comparing actuals to Petitioner's Phase 1 forecast. Any variance between actuals and the Phase 1 forecast greater than 10% should be explained.

(6) Calculation of Phase 1 rates based on the December 31, 2023 actuals as certified.

E. <u>Other Implementation Considerations</u>

Q: When does Petitioner propose its updated depreciation rates be implemented?

A: Petitioner proposes its updated depreciation rates be implemented when an order is issued in this case as part of its Phase 1 rates.

Q: Do you accept this proposal?

A: No. Implementation of Petitioner's rates before the beginning of its forward-looking test year is neither appropriate nor supported. Therefore, I recommend Petitioner's approved depreciation rates not be implemented until the beginning of its forward-looking test year.

Q: Does Petitioner propose any interim rate increases during its forward-looking test year?

A: Yes. Petitioner proposes up to three additional interim increases during its forward-looking test year. Ms. Behme explains that Petitioner has been authorized to accrue post-in-service carrying costs for each of the combustion turbine projects approved in Cause No. 45564 and the Posey Solar project approved in Cause No. 45847. All these projects are projected to be placed in service during the test year. (Behme at p. 8.)

Q: Why does Petitioner say it proposes to implement three rate increases within the test year?

A: Ms. Behme testified that if the post-in-service carrying costs on these projects accrue until the end of the test year, rate base and Phase 3 rates will be higher than if these projects were reflected in rates earlier, when they are placed in service. (Brehme at p. 9.) Petitioner proposes to implement interim increases to reflect the additional after-tax return and depreciation expense on each of these projects using the capital structure in effect at the beginning of the test year. These interim steps would take effect upon filing of a certification that the plant in question is in service.

Q: Do you accept Petitioner's proposal regarding interim rates?

A: No. This proposal unnecessarily complicates Petitioner's rates, is unprecedented, undermines an already well-established process for updating rate base in forward-looking test year cases, increases regulatory costs and burdens, and would serve to confuse customers without any quantification of the benefit to ratepayers in avoiding less than twelve months of carrying costs.

V. RATE REQUEST PRESENTATION -- CONCERNS AND ISSUES

Q: What presentation deficiencies did the OUCC encounter in its review of Petitioner's revenue requirement?

A: The OUCC encountered difficulties with the presentation of Petitioner's revenue requirements and schedules as presented in Exhibit No. 20 - Financial Exhibit. The parties to this case are tasked with reviewing Petitioner's entire request, including the revenue requirement proposed for each phase of the increase as well as the overall rate increase proposed. However, the financial model provided by Petitioner was deficient in several material respects, thwarting a thorough and comprehensive review.

Q: What deficiencies did the OUCC encounter?

A: Four material deficiencies in Petitioner's revenue requirement model, Exhibit No. 20 (Excel version) hindered the OUCC's review:

(1) The financial model presented in Exhibit No. 20 does not include the entire forecast;

(2) The financial model presented only the overall revenue requirement and rate increase proposed;

(3) A majority of the inputs to the schedules and workpapers were merely hard-coded cell entries, with no indication as to how the amount was determined or the basis for the calculation of the amount entered; and

(4) Lack of detailed supporting calculations for the adjustments that are included in Petitioner's Exhibit No. 20.

Q: What do you mean when you say the financial model does not include the entire forecast?

A: The various schedules and workpapers included in its financial model (Petitioner's Exhibit No. 20) included values entered in a column heading designated as "Test Year Unadjusted" Or "Unadjusted Test Year." However, all references to the amounts included in these columns were ultimately hard-coded cell entries with no additional information provided.

Q: Did the OUCC request the financial model that supported the "Test Year Unadjusted" forecast?

A: Yes. In response to discovery (OUCC Attachment MAS-8.), Petitioner admitted that there are no formulas or spreadsheets that pull together the various inputs to create the Test Year unadjusted forecast.:

> The "Test Year Unadjusted" forecast was developed based on the 2025 forecasted needs of CEI South's operational units, including operational areas such as generation, distribution, and high voltage operations. It was not a buildup per se from historical costs because it was based on the forecasted needs for a year that was going to be different than prior years. Operational units forecasted both operational costs and workforce staffing levels necessary for CEI South to run the electric business safely, reliably and effectively during the period the rates are anticipated to be in effect… For direct O&M, the forecasted needs of the operational units were loaded into the accounting and forecasting system utilizing cost objects, which are used to assign FERC accounts. Allocated costs were also loaded into the accounting system. The other components of the forecast, which are based on information provided by others, including margin, fuel, purchased power and capacity purchases, property taxes, depreciation, other income, and an estimated allocation of interest expense and income taxes were also input into the accounting system by cost objects. The system then combines the inputs to generate a CEI South Electric income statement. There are no formulas or spreadsheets that pull together the various inputs to create the Test Year Unadjusted forecast. It is based on a report generated by the accounting system – SAP.

Thus, Petitioner acknowledged Test Year Unadjusted values are merely the output of a report generated by its accounting system.

Q: Was a satisfactory explanation provided?

A: No. Without the information input into SAP to generate Petitioner's projected income statement, there is no basis on which to conclude any expense or revenue amount is reasonable. Whether a utility builds its projections based on an historical base period or uses some other methodology, it does not relieve that utility of its responsibility to provide, in its case-in-chief, the entire financial model used to develop those projections or the supporting calculations and information necessary to evaluate those projections.

Q: Why is it important for Petitioner to provide its projections for each phase of its proposed rate increase?

A: To allow a reasonable review of its revenues and expenses, any utility using a forward-looking test year must provide the forecast for each month of the forward-looking test year and each month of the linking period. Such provision also allows the reviewer to determine whether Petitioner is being consistent in its forecasting methodologies. It also aids in verifying the rate increase Petitioner states for each phase of its proposal. It is not enough for Petitioner to merely describe in testimony what it proposes. It is also necessary to provide the amounts and calculations in its financial forecast model so that it can be verified that what Petitioner said it was proposing was supported.

Q: Didn't Petitioner provide its forecast for its proposed Phases 1 and 2 in Attachments CMB-4 and CMB-5?

A: No. Attachments CMB-4 and CMB-5 presented only selected schedules from the model and all numbers presented were merely hard-coded cell entries. No computations were included and, more importantly, no monthly data was provided for the associated linking period for each phase.

Q: Were there other instances where only hard-coded amounts were entered into cells?

A: Yes. Many of the schedules and workpapers provided to support each of the 39 adjustments included in the model, also included only hard-coded cell entries with no explanation as to how the amount was determined. For example, Schedule C-3.32 reflects the adjustment to annualize the operating expenses associated with Posey Solar.

Table 2: <u>Schedule C-3.32 – Annualized Posey Solar Expense Adjustment</u>

Description		Amount	
PURPOSE and DESCRIPTION: To annualize the operating expense associated with Posey Solar.			
Adjusted Posey Solar Operating Expense		$ 5,381,014	(Cell D19)
Unadjusted Posey Solar Operating Expense		$ 4,988,677	(Cell D21)
Pro Forma Adjustemnt for Posey Solar Operating Expense		$ 392,337	
Expense by FERC			
	553	300,301	
	548	92,036	
	Total	392,337	
	Hard-coded cell entries		

It is unclear what is included in "Adjusted Posey Solar Operating Expenses," including the source of the hard-coded number entered into Cell D19. Similarly, it is unclear what is included in "Unadjusted Posey Solar Operating Expenses," including the source of that hard-coded number entered into Cell D21.

The adjustment is broken down into FERC accounts but again there is no explanation as to what these adjustments represent or what specific costs are being adjusted. Based on this "support" there is literally no meaningful data that can be reviewed or evaluated. Posey Solar is still under construction and is not expected to be in service until the middle of Petitioner's test year.

When Petitioner neglects to provide key supporting information in its case-in-chief, it is not just denying this evidence to the OUCC and other consumer parties. It is also denying this evidence to the Commission and its staff, evidence that is essential to the determination of whether Petitioner has met its burden of proof and whether it is entitled to a rate increase.

Q: Do you have any further comments regarding Petitioner's presentation of its revenue requirement and lack of support for its proposal?

A: In its general administrative order ("GAO") 2013-5, the Commission reiterated that "A utility petitioning for a change in its rates and charges bears the burden of proof and must submit sufficient evidence as part of its case in chief to satisfy its burden of proof." (See GAO 2013-5, Appendix A, II(A).) Petitioner largely failed in this responsibility.

VI. <u>RECOMMENDATIONS</u>

Q: Please summarize your recommendations to the Commission.

A: In accordance with the foregoing testimony, I recommend the Commission issue findings consistent with the following:

(1) Acceptance of Petitioner's proposed tax adjustment rider ("TAR") with the understanding that the current tax mechanisms will continue to charge or

credit the same customer classes in the same manner as they are currently being implemented.

(2) Acceptance of Petitioner's proposed pass back of state excess accumulated deferred income taxes outside base rates, including carrying costs as described above, over a three-year period. I also recommend Petitioner be required to submit a post-order compliance filing within three months of the date a final order is issued in this case showing (1) the growth of this liability by year from 2011 to the date Petitioner begins refunding this liability and (2) the detailed calculation of the carrying costs included in the amount to be refunded. Petitioner should also make a compliance filing once all monies are refunded to customers, certifying that all monies owed to customers have been paid and indicating the amount refunded to customers in each year.

(3) Denial of Petitioner's proposed tracker proving a return on any increase or decrease in its corporate alternative minimum tax carryforward that occurs between rate cases. Alternatively, if Petitioner is authorized this treatment, I recommend Petitioner be required to track <u>all</u> tax related components of cost-free capital, not just the components that benefit Petitioner.

(4) Denial of Petitioner's proposed implementation of a rate increase prior to the start of its forward-looking test year. If the Commission finds it is appropriate to implement rates before the beginning of the forward-looking test year, a post-order review process should be implemented similar to the process to be implemented at the beginning and end of Petitioner's forward-looking test year. Petitioner should be required to make a compliance filing to be submitted no sooner than the issuance of an order in this Cause. In no event should the information Petitioner proposes to provide with its rebuttal filing be considered in the determination of any Phase 1 increase authorized in the Commission's final order in this Cause.

(5) Acceptance of Petitioner's proposed process for implementing rates at the beginning and end of its forward-looking test year with some modifications.

a. In each phase, total rate base should not exceed the value of rate base as of the end of the forward-looking test year approved by the Commission in the final order. To the extent the actual value of rate base exceeds approved rate base as of December 31, 2025, the difference should be removed from actual rate base for purposes of determining the rates to be implemented in each phase.

b. Any amounts invested in excess of the cap are eligible for inclusion in other rate or tracker proceedings.

c. If Petitioner does not actually invest what it forecasted it would invest in utility plant in service, adjustments to depreciation expense and property tax, along with associated adjustments to income tax expense, should be made to reflect actual investments in utility plant in service.

d. A technical conference may be convened at the request of any party or the Commission staff to allow further discussion in determining whether the compliance filing complies with the order and determine what additional information should be provided in each phase.

e. Compliance filing should include the following:

   i. Certification of Petitioner's actual utility plant in service and actual capital structure.

   ii. Actual rate base by component, in a similar format to that of Exhibit No. 20, Schedule B-1.1 and comparing actuals to Petiitoner's forecast. Any variances between actuals and the forecast greater than 10% should be explained.

   iii. Actual utility plant in service balances by FERC Account similar to Exhibit No. 20, Schedule B-2.1.

   iv. Actual accumulated depreciation balances by FERC Account similar to Exhibit No. 20, Schedule B-3.1.

   v. Actual capital structure by component, in a format similar to that of Exhibit No. 20, Schedule D-1.1, including an updated calculation of weighted average cost of capital and comparing actuals to Petitioner's forecast. Any variance between actuals and forecast greater than 10% should be explained.

   vi. Calculation of Phase 1 rates based on the December 31, 2023 actuals as certified.

(6) Petitioner's approved depreciation rates should not be implemented until the beginning of its forward-looking test year.

(7) Denial of Petitioner's proposal to implement rate increases *during* the forward-looking test year.

Q: Does this conclude your testimony?

A: Yes.

APPENDIX A

Q: Please describe your educational background and experience.

A: I graduated from the University of Houston at Clear Lake City in August 1982 with a Bachelor of Science degree in Accounting. From 1982 to 1985, I held the position of Gas Pipeline Accountant at Seagull Energy in Houston, Texas. From 1985 to 2001, I worked for Enron in various positions of increasing responsibility and authority. I began in gas pipeline accounting, was promoted to a position in financial reporting and planning for both the gas pipeline group and the international group, and finally was promoted to a position providing accounting support for infrastructure projects in Central and South America. In 2002, I moved to Indiana, where I held non-utility accounting positions in Indianapolis. In August 2003, I accepted a utility analyst position with the OUCC. I was promoted to Senior Utility Analyst in 2011. In 2018, I was promoted to my current position as Chief Technical Advisor.

Since joining the OUCC I have attended the National Association of Regulatory Utility Commissioners ("NARUC") Eastern Utility Rate School in Clearwater Beach, Florida, and the Institute of Public Utilities' Advanced Regulatory Studies Program in East Lansing, Michigan. I have also attended several American Water Works Association and Indiana Rural Water Association conferences as well as the National Association of Utility Consumer Advocates ("NASUCA") Water Committee Forums. I have participated in the NASUCA Water Committee and the NASUCA Tax and Accounting Committee, including serving as chair for the Tax and Accounting Committee from 2016 – 2021.

Q: Have you previously testified before the Indiana Utility Regulatory Commission?

A: Yes. I have testified before the Commission as an accounting witness in various causes involving water, wastewater, electric, and gas utilities.

Q: Have you held any professional licenses?

A: Yes. I passed the CPA exam in 1984 and was licensed as a CPA in the State of Texas until I moved to Indiana in 2002.

AFFIRMATION

I affirm the representations I made in the foregoing testimony are true to the best of my knowledge, information, and belief.

Margaret A. Stull

By: Margaret A. Stull
Cause No. 45990
Office of Utility Consumer Counselor (OUCC)

Date: March 12, 2024

Q 7.13 On page 12 of her direct testimony, Ms. Story states there is a regulatory liability for Indiana state EADIT of $11, 412,319. Please provide the detailed calculation of this regulatory liability, showing the build-up of the liability by year from 2012 through the Base Period ending December 31, 2022.

Response: Please see the following attachment for the calculation supporting the balances each year.

Attachment:

- 45990 - Attachment OUCC DR07 7.13 State Rate Change.xlsx

CEI SOUTH
CAUSE NO. 45990
ADJUSTED FEDERAL INCOME TAXES
PHASE 2

SCHEDULE C-5
PAGE 1 OF 3
WITNESS RESPONSIBLE:
J.K. STORY

		AT CURRENT RATES					AT PROPOSED RATES	
Line	Description	Unadjusted (A)	Adjustments (B)	Adjusted (C)	Tax Rate Annualization (D)	Adjusted (E)	Adjustments (F)	Proposed (G)
1	Operating Income Before State Income Taxes	$ 129,676,572	$ (33,110,201)	$ 96,566,370	$ -	$ 96,566,370	$ (111,204,347)	$ (14,637,977)
2	Other Taxes	2,838,115	(15,898)	2,822,217	-	2,822,217	-	2,822,217
3	State Income Tax Expense	4,294,496	671,163	4,965,659	-	4,965,659	(5,449,013)	(483,354)
4	Operating Income Before Federal Income Taxes	$ 122,543,961	$ (33,765,466)	$ 88,778,495	$ -	$ 88,778,495	$ (105,755,334)	$ (16,976,839)
5								
6	Reconciling Items:							
7	Net Interest Charges	$ 44,558,692	$ (48,046,977)	$ (3,488,285)	$ -	$ (3,488,285) *	$ -	$ (3,488,285)
8								
9	Tax Depreciation	$ 155,123,790	$ 50,157,008	$ 205,280,798	$ -	$ 205,280,798	$ -	$ 205,280,798
10	Book Depreciation	120,769,887	-	120,769,887	-	120,769,887	-	120,769,887
11	Excess of Tax over Book Depreciation	$ 34,353,903	$ 50,157,008	$ 84,510,911	$ -	$ 84,510,911	$ -	$ 84,510,911
12								
13	Non-Deductible Expenses	$ 17,666,307	$ (18,951,625)	$ (1,285,318)	$ -	$ (1,285,318)	$ -	$ (1,285,318)
14	Test Year Below the Line Expense/(Revenue)	(45,597,616)	45,597,616	-	-	-	-	-
15	Total Permanent Differences - Expense/(Revenue)	$ (27,931,309)	$ 26,645,991	$ (1,285,318)	$ -	$ (1,285,318)	$ -	$ (1,285,318)
16								
17	Other Reconciling Items:							
18	Unbilled Revenue	$ (11,071)	$ 11,071	$ -		$ -		$ -
19	Property Taxes	(173,158)		(173,158)		(173,158)		(173,158)
20	Bad Debts	133,493		133,493		133,493		133,493
21	Record Sec. 263A CAP Costs	148,539		148,539		148,539		148,539
22	Prepaid Insurance	-		-		-		-
23	Construction Deposits	963,728		963,728		963,728		963,728
24	FASB 106 Costs	-		-		-		-
25	MGP Reserve Net of Insurance	11,887		11,887		11,887		11,887
26	Reverse Exec Restricted Stock Accr	-		-		-		-
27	Deferred Comp/Long-term Incentive Plan	(290,545)	290,545	-		-		-
28	Amortization of Debt Expense	(183,650)		(183,650)		(183,650)		(183,650)
29	Deferred Debits/Regulatory Assets	(4,705,379)		(4,705,379)		(4,705,379)		(4,705,379)
30	Pension Expense in Excess of Tax	-		-		-		-
31	Allowance for Funds Used During Construction	-	-	-		-		-
32	AFUDC Debt	(2,351,076)		(2,351,076)		(2,351,076)	2,098,502	(252,574)
33	Capitalized Interest	2,405,663		2,405,663		2,405,663		2,405,663
34	Contributions in Aid of Construction	2,245,030		2,245,030		2,245,030		2,245,030
35	Mixed Service Cost	(21,127,602)		(21,127,602)		(21,127,602)		(21,127,602)
36	Capitalized Vehicle Taxes	(23,862)		(23,862)		(23,862)		(23,862)
37	Capitalized Property Taxes	-		-		-		-
38	Restricted Stock	-		-		-		-
39	Repairs Deduction	(11,903,084)		(11,903,084)		(11,903,084)		(11,903,084)
40	Total Other Reconciling Items	$ (34,861,087)	$ 301,616	$ (34,559,471)	$ -	$ (34,559,471)	$ 2,098,502	$ (32,460,969)
41	Total Reconciling Items	$ 85,842,372	$ 28,454,406	$ 114,296,779	$ -	$ 114,296,779	$ (2,098,502)	$ 112,198,276
42	Federal Taxable Income/(Loss)	$ 36,701,589	$ (62,219,873)	$ (25,518,284)	$ -	$ (25,518,284)	$ (103,656,832)	$ (129,175,116)

* - From WPC-4.

CEI SOUTH
CAUSE NO. 45990
ADJUSTED FEDERAL INCOME TAXES
PHASE 2

SCHEDULE C-5
PAGE 2 OF 3
WITNESS RESPONSIBLE:
J.K. STORY

		AT CURRENT RATES					AT PROPOSED RATES	
Line	Description	Unadjusted (A)	Adjustments (B)	Adjusted (C)	Tax Rate Annualization (D)	Adjusted (E)	Adjustments (F)	Proposed (G)
1	Federal Taxable Income/(Loss)	$ 36,701,589	$ (62,219,873)	$ (25,518,284)	$ -	$ (25,518,284)	$ (103,656,832)	$ (129,175,116)
2	Net Operating Loss Generation (Utilization)		$ 47,512,003	$ 25,518,284	$ -	$ 25,518,284	$ (25,518,284)	
3	Taxable Income (Loss) After Net Operating Loss	$ 36,701,589	$ (14,707,870)	$ -	$ -	$ -	$ (129,175,116)	$ (129,175,116)
4								
5	Federal Income Tax Rate	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%
6								
7	Federal Income Taxes	$ 7,707,334	$ (7,707,334)	$ -	$ -	$ -	$ (27,126,774)	$ (27,126,774)
8	Plus: Credits and Other Adjustments	$ (4,618,681)	$ 4,618,681	$ -	$ -	$ -	$ -	$ -
9	Total Federal Income Taxes	$ 3,088,653	$ (3,088,653)	$ -	$ -	$ -	$ (27,126,774)	$ (27,126,774)
10								
11	Corporate Alternative Min Tax Calc							
12	Net Income (Before Income Taxes)	$ -	$ 96,566,370	$ 96,566,370	$ -	$ 96,566,370	$ (111,204,347)	$ (14,637,977)
13	State Income Tax Deduction	$ -	$ (4,965,659)	$ (4,965,659)	$ -	$ (4,965,659)	$ 5,449,013	$ 483,354
14	Pension Adjustment	$ -	$ 18,548	$ 18,548	$ -	$ 18,548	$ -	$ 18,548
15	§168 Depreciation Adjustment	$ -	$ (18,193,875)	$ (18,193,875)	$ -	$ (18,193,875)	$ -	$ (18,193,875)
16								
17	Adjusted Financial Statement Income (AFSI)	$ -	$ 73,425,385	$ 73,425,385	$ -	$ 73,425,385	$ (105,755,334)	$ (32,329,949)
18								
19	Federal Alternative Minimum Tax Rate	15.000%	15.000%	15.000%	15.000%	15.000%	15.000%	15.000%
20								
21	Total Federal Minimum Tax	$ -	$ 11,013,808	$ 11,013,808	$ -	$ 11,013,808	$ (15,863,300)	$ (4,849,492)
22	Research and Development Credit	$ -	$ (1,205,130)	$ (1,205,130)	$ -	$ (1,205,130)	$ -	$ (1,205,130)
23	Total Federal Income Tax	$ -	$ 9,808,678	$ 9,808,678	$ -	$ 9,808,678	$ (15,863,300)	$ (6,054,622)
24								
25	Provision Deferred Inc Taxes (Net):							
26	Method Life	$ 7,214,320	$ 10,532,971.68	$ 17,747,291	$ -	$ 17,747,291	$ -	$ 17,747,291
27	Unbilled Revenue	2,325	(2,325)	-	-	-	-	-
28	Property Taxes	36,363	-	36,363	-	36,363	-	36,363
29	Bad Debts	(28,034)	-	(28,034)	-	(28,034)	-	(28,034)
30	Record Sec. 263A CAP Costs	(31,193)	-	(31,193)	-	(31,193)	-	(31,193)
31	Prepaid Insurance	-	-	-	-	-	-	-
32	Construction Deposits	(202,383)	-	(202,383)	-	(202,383)	-	(202,383)
33	FASB 106 Costs	-	-	-	-	-	-	-
34	MGP Reserve Net of Insurance	(2,496)	-	(2,496)	-	(2,496)	-	(2,496)
35	Reverse Exec Restricted Stock Accr	-	-	-	-	-	-	-
36	Deferred Comp/Long-term Incentive Plan	61,014	(61,014)	-	-	-	-	-
37	Amortization of Debt Expense	38,567	-	38,567	-	38,567	-	38,567
38	Deferred Debits/Regulatory Assets	988,130	-	988,130	-	988,130	-	988,130
39	Other Adjustments	1,159,544	(1,159,544)	-	-	-	-	-
40	Allowance for Funds Used During Construction	-	-	-	-	-	-	-
41	AFUDC Debt	493,726	-	493,726	-	493,726	(440,685)	53,040
42	Capitalized Interest	(505,189)	-	(505,189)	-	(505,189)	-	(505,189)
43	Contributions in Aid of Construction	(471,456)	-	(471,456)	-	(471,456)	-	(471,456)
44	Mixed Service Cost	4,436,796	-	4,436,796	-	4,436,796	-	4,436,796
45	Capitalized Vehicle Taxes	5,011	-	5,011	-	5,011	-	5,011
46	NOL Carryforward	-	(5,358,840)	(5,358,840)	-	(5,358,840)	5,358,840	-
47	CAMT Carryforward	-	(9,808,678)	(9,808,678)	-	(9,808,678)	(11,263,474)	(21,072,152)
48	Repairs Deduction	2,499,648	-	2,499,648	-	2,499,648	-	2,499,648
49	Total Prov Def. Inc Tax	$ 15,694,692	$ (5,857,429)	$ 9,837,263	$ -	$ 9,837,263	$ (6,345,320)	$ 3,491,943
50	Total Federal Income Taxes	$ 18,783,344	$ 3,951,249	$ 19,645,941	$ -	$ 19,645,941	$ (22,208,620)	$ (2,562,680)

CEI SOUTH
CAUSE NO. 45990
ADJUSTED FEDERAL INCOME TAXES
PHASE 2

SCHEDULE C-5
PAGE 3 OF 3
WITNESS RESPONSIBLE:
J.K. STORY

		AT CURRENT RATES					AT PROPOSED RATES	
Line	Description	Unadjusted (A)	Adjustments (B)	Adjusted (C)	Tax Rate Annualization (D)	Adjusted (E)	Adjustments (F)	Proposed (G)
1								
2	Federal Excess Deferred Income Tax Amortization	(4,716,273)	4,716,273	-		-		-
3	Federal Consoildated Return Benefit of Interest Expense	-	(4,066,270)	(4,066,270)		(4,066,270)		(4,066,270)
4								
5	Total Federal Income Tax Expense	$ 14,067,071	$ 4,601,252	$ 15,579,671	$ -	$ 15,579,671	$ (22,208,620)	$ (6,628,949)
6								
7	Total State Income Tax Expense	$ 4,294,496	$ 671,163	$ 4,965,659	$ -	$ 4,965,659	$ (5,449,013)	$ (483,354)
8	Total Income Tax Expense	$ 18,361,567	$ 5,272,415	$ 20,545,329	$ -	$ 20,545,329	$ (27,657,633)	$ (7,112,304)
9								
10	Total Operating Income Before Income Taxes	$ 122,543,961	$ (33,765,466)	$ 88,778,495	$ -	$ 88,778,495	$ (105,755,334)	$ (16,976,839)
11	Plus: State Income Tax Expense	4,294,496	671,163	4,965,659	-	4,965,659	(5,449,013)	(483,354)
12	Less: Interest Expense	44,558,692	(48,046,977)	(3,488,285)	-	(3,488,285)	-	(3,488,285)
13	Less: Test Year Below the Line Expense/(Revenue)	(45,597,616)	45,597,616	-	-	-	-	-
14	Net Income Before Income Taxes	$ 127,877,381	$ (30,644,943)	$ 97,232,438	$ -	$ 97,232,438	$ (111,204,347)	$ (13,971,909)
15								
16	Effective Tax Rate	14.36%						50.90%

Sign In / Register

News Release

<< Back

Apr 29, 2021

CenterPoint announces sale of Arkansas and Oklahoma natural gas LDC businesses to Summit Utilities for $2.150 billion in cash

- *CenterPoint to receive $2.150 billion in cash, including recovery of approximately $425 million in cash of unrecovered storm-related incremental natural gas costs incurred in February 2021*
- *Transaction represents a landmark valuation at 38.0x 2020 earnings and 2.5x 2020 year-end rate base*
- *Sale proceeds will allow CenterPoint to recycle capital to fund its industry-leading 10% planned compound annual rate base growth*
- *Sale will not impact company's targeted 6% - 8% annual utility non-GAAP EPS growth rate*
- *Sale demonstrates significantly higher market value for natural gas infrastructure assets, including CenterPoint's remaining gas businesses*

HOUSTON--(BUSINESS WIRE)--Apr. 29, 2021-- CenterPoint Energy, Inc. (NYSE: CNP) ("CenterPoint") today announced the sale of its Arkansas and Oklahoma natural gas LDC assets to Summit Utilities for $2.150 billion in cash, including recovery of approximately $425 million in cash of unrecovered storm-related incremental natural gas costs incurred in February 2021, subject to true-up at transaction close. The assets include approximately 17,000 miles of main pipeline in Arkansas, Oklahoma, and Texarkana serving more than half a million customers residing in high-quality regulatory jurisdictions.

The proceeds of $1.725 billion in cash, after recovery of approximately $425 million in cash unrecovered storm costs, represents a 2.5x multiple of 2020 rate base and a 38.0x multiple of 2020 earnings. The transaction is anticipated to close by the end of 2021, subject to customary closing conditions, including Hart-Scott Rodino antitrust clearance and state regulatory approvals.

CenterPoint President and CEO Dave Lesar said, “I could not be more excited to share this announcement today. Summit Utilities is a seasoned operator of utility assets in the region and the ideal company to acquire these assets. We are excited that Summit has existing businesses in Arkansas and Oklahoma, which will facilitate the transition process for our employees and customers. Summit has an industry track record of being a high-quality operator and we are confident they will continue to provide safe, reliable, and low-cost natural gas service to our customers in Arkansas and Oklahoma.”

Lesar added, “This transaction reflects the hard work and determination of everyone on the CenterPoint team. This valuation represents a landmark multiple for the LDC space and is a clear testament of the premium utility assets in these two jurisdictions. These assets are a proven integral part of the energy supplies in the states in which they operate. The solid customer demand for reliable and efficient distribution of natural gas was only solidified by the recent winter storm events. We believe the price paid for these assets demonstrates that the market is significantly undervaluing the remainder of our natural gas businesses.”

“The announcement demonstrates not only our ability to efficiently recycle capital across our utility footprint, but also our ability to execute on our commitments to our shareholders. As outlined in our December 2020 Investor Day, our commitments include delivering annualized utility earnings per share growth of 6% - 8% and growing our rate base at a 10% compound annual growth rate. The ability to efficiently redeploy this capital and the eventual exit of the midstream investments will have no impact on our targeted 6% - 8% annualized earnings per share growth rate. Further, we will also be eliminating the Oklahoma and Arkansas storm-related incremental natural gas cost from our balance sheet,” said Lesar.

“We look forward to announcing our first quarter of 2021 financial results during our earnings call on May 6,” he said.

J.P. Morgan Securities LLC. and RBC Capital Markets, LLC. served as CenterPoint Energy’s financial advisors. Baker Botts L.L.P. served as CenterPoint Energy’s legal advisors.

About CenterPoint Energy, Inc.

As the only investor-owned electric and gas utility based in Texas, CenterPoint Energy, Inc. (NYSE: CNP) is an energy delivery company with electric transmission and distribution, power generation and natural gas distribution operations that serve more than 7 million metered customers in Arkansas, Indiana, Louisiana, Minnesota, Mississippi, Ohio, Oklahoma and Texas. As of December 31, 2020, the company owned approximately $33 billion in assets and also owned 53.7 percent of the common units representing limited partner interests in Enable Midstream Partners, LP, a publicly traded master limited partnership that owns, operates and develops strategically located natural gas and crude oil infrastructure assets. With approximately 9,500 employees, CenterPoint Energy and its predecessor companies have been in business for more than 150 years. For more information, visit CenterPointEnergy.com.

About Summit Utilities, Inc.

Summit Utilities, Inc. (Summit) owns natural gas distribution and transmission subsidiaries that operate in Arkansas, Colorado, Maine, Missouri, and Oklahoma. The company provides safe, clean and affordable natural gas to businesses and residents in five states through Colorado Natural Gas, Inc., Summit Natural Gas of Missouri, Inc., Summit Natural Gas of Maine, Inc. and Arkansas Oklahoma Gas Corporation. Each of Summit’s subsidiaries constructs and installs natural gas distribution systems with the goal of supporting economic development by providing clean-burning, safe and reliable natural gas to residential and commercial customers through exceptional customer service and commitment to community. Overall, Summit entities serve approximately 100,000 customers and operate more than 5,400 miles of pipeline in Arkansas, Colorado, Maine, Missouri and Oklahoma.

Use of Non-GAAP Measures

As included in this press release, our utility growth target of 6-8% is based on a non-GAAP utility earnings per share ("Utility EPS"), which is not a generally accepted accounting principles ("GAAP") financial measure. This non-GAAP EPS based utility growth rate has been previously referenced by the CenterPoint Energy as the guidance-based growth rate. Generally, a non-GAAP financial measure is a numerical measure of a company's historical or future financial performance that excludes or includes amounts that are not normally excluded or included in the most directly comparable GAAP financial measure. The Utility EPS reflects dilution and earnings as if the Company's Series B Preferred Stock converted on their mandatory conversion date. Utility EPS considers assumptions for certain significant variables that may impact earnings, such as customer growth and usage including normal weather, throughput, recovery of capital invested, effective tax rates, financing activities and related interest rates, regulatory and judicial proceedings. In addition, the Utility EPS assumes a continued re-opening of the economy in CenterPoint Energy's service territories throughout 2021. To the extent actual results deviate from these assumptions, the Utility EPS may not be met and our projected annual Utility EPS growth rate range may change. Utility EPS includes an allocation of corporate overhead based upon our Utility segments relative earnings contribution. Corporate overhead consists primarily of interest expense, preferred stock dividend requirements and other items directly attributable to the parent along with associated income taxes, and considers certain significant variables that may impact earnings. Utility EPS excludes (a) earnings or losses from the change in value of the Company's 2.0% Zero-Premium Exchangeable Subordinated Notes due 2029 ("ZENS") and related securities, (b) certain expenses associated with merger integration, and (c) Midstream Investments, including income from the Enable preferred units and a corresponding amount of debt in addition to an associated allocation of corporate overhead based on relative earnings contribution. Utility EPS also does not include other potential impacts, such as changes in accounting standards, impairments or unusual items, which could have a material impact on GAAP reported results for the applicable guidance period. CenterPoint Energy is unable to present a quantitative reconciliation of forward-looking Utility EPS because changes in the value of ZENS and related securities, future impairments and other unusual items are not estimable as they are highly variable and difficult to predict due to various factors outside of management's control. Management evaluates CenterPoint Energy's financial performance in part based on Utility EPS. Management believes that presenting this non-GAAP financial measure enhances an investor's understanding of CenterPoint Energy's overall financial performance by providing them with an additional meaningful and relevant comparison of current and anticipated future results across periods. The adjustments made in this non-GAAP financial measure exclude items that Management believes does not most accurately reflect the Company's fundamental business performance. CenterPoint Energy's Utility EPS non-GAAP financial measure should be considered as a supplement to, and not as a substitute for, or superior to, diluted earnings per share, which is the most directly comparable GAAP financial measure. This non-GAAP financial measure also may be different than non-GAAP financial measures used by other companies.

Forward-Looking Statements

The statements in this press release contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this press release are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this press release, the words “anticipate,” “believe,” “continue,” “could,” “estimate,” “expect,” “forecast,” “goal,” “intend,” “may,” “objective,” “plan,” “potential,” “predict,” “projection,” “should,” “target,” “will” or other similar words are intended to identify forward-looking statements. These forward-looking statements are based upon assumptions of management which are believed to be reasonable at the time made and are subject to significant risks and uncertainties. Actual events and results may differ materially from those expressed or implied by these forward-looking statements. Forward-looking statements include, but are not limited to, statements relating to the consideration CenterPoint Energy expects to receive, the timing of closing the transaction, long-term growth strategy and investment plan, capital deployment, rate base growth, and CenterPoint Energy’s guidance basis utility earnings per share and guidance basis utility earnings per share growth target. Each forward-looking statement contained in this press release speaks only as of the date of this release. Important factors that could cause actual results to differ materially from those indicated by the provided forward-looking information include risks and uncertainties relating to: (1) the timing of the expiration or termination of the Hart-Scott-Rodino waiting period and the receipt of any consents, waivers or approvals required to be obtained pursuant to applicable antitrust or regulatory laws, (2) the occurrence of any event, change or other circumstances that could give rise to the termination of the proposed transactions or could otherwise cause the failure of the proposed transactions to close, (3) the risk that a condition to the closing of the proposed transactions may not be satisfied, (4) the outcome of any legal proceedings, regulatory proceedings or enforcement matters that may be instituted relating to the proposed transactions, (5) the timing to consummate the proposed transactions, (6) disruption from the proposed transactions making it more difficult to maintain relationships with customers, employees, regulators or suppliers, (7) the diversion of management time and attention on the proposed transactions and (8) other factors discussed in CenterPoint Energy’s Annual Report on Form 10-K for the fiscal year ended December 31, 2020 and other reports CenterPoint Energy or its subsidiaries may file from time to time with the Securities and Exchange Commission (SEC).

View source version on businesswire.com:
https://www.businesswire.com/news/home/20210429005557/en/

Media:
John Sousa
Phone: 713.659.2111

Investors:
Philip Holder
Jackie Richert
Phone: 713.207.6500

Source: CenterPoint Energy, Inc.

Sign In / Register

News Release

<< Back
Feb 20, 2024

CenterPoint Energy announces sale of its Louisiana and Mississippi natural gas assets to Bernhard Capital Partners for $1.2 billion

- *Transaction valuation represents approximately 32 multiple of 2023 Louisiana and Mississippi Local Distribution (LDC) earnings*
- *Sale will enable company to efficiently recycle approximately $1 billion in anticipated after-tax cash proceeds to support industry-leading capital plan*
- *Transaction also enables CenterPoint to reprioritize future capital investments related to those assets of approximately $1 billion elsewhere across its regulated Electric and Natural Gas utility footprint*
- *Closing expected toward the end of first quarter of 2025*

- *Sale will not change company's targeted utility non-GAAP EPS growth rate of 8% in 2024, and the mid-to-high end of 6%-8% annually from 2025 through 2030*
- *Company reiterates long-term confidence in and commitment to its Natural Gas Business*

HOUSTON--(BUSINESS WIRE)--CenterPoint Energy, Inc. (NYSE: CNP) ("CenterPoint") today announced the sale of its Louisiana and Mississippi natural gas LDC businesses to Bernhard Capital Partners, a services and infrastructure-focused private equity management firm, for $1.2 billion. The assets include approximately 12,000 miles of main pipeline in Louisiana and Mississippi serving approximately 380,000 metered customers. CenterPoint's LDCs are the second largest natural gas LDCs in both Louisiana and Mississippi by customer accounts, with a combined workforce of approximately 550 employees.

The sales price of $1.2 billion represents approximately 32 multiple of 2023 Louisiana and Mississippi LDC earnings. The transaction is anticipated to close toward the end of first quarter of 2025, subject to customary closing conditions, including Hart-Scott-Rodino antitrust clearance and state regulatory approvals.

"I would like to thank our Louisiana and Mississippi LDC employees, as well as the team members who support these businesses, for their focus on safety, performance, and results. Together, they are our customers' trusted energy partner in these regions," said Jason Wells, President and Chief Executive Officer of CenterPoint. "The transaction will allow us to optimize our portfolio of utility operations and efficiently recycle approximately $1 billion in after-tax cash proceeds into our service territory where we have both electric and natural gas operations or where we have a larger presence at a valuation that is more efficient than issuing common equity. The sale will also enable us to redeploy approximately $1 billion of future capital expenditures intended for Louisiana and Mississippi into jurisdictions with less regulatory lag thereby enhancing the ongoing earnings power of the company."

Wells added, "This will mark the fourth time over the past few years in which we have recycled sales proceeds and reinvested them in our regulated businesses for the benefit of all stakeholders. The transaction, along with the reinvested capital, will not change our targeted non-GAAP EPS growth rate of 8% in 2024, and the mid-to-high end of 6%-8% annually from 2025 through 2030. The efficiency of this transaction and portfolio optimization will further enhance our ability to continue executing our industry-leading long-term growth strategy for years to come.

"Our Natural Gas Business is core to our company and together with our Electric Business will continue to be a cornerstone of our long-term growth strategy," said Wells. "From an operational and strategic perspective, we remain confident in and committed to our regulated natural gas utilities in Texas, Indiana, Minnesota, and Ohio where we have significant footprints and rate bases." CenterPoint's Louisiana and Mississippi LDCs represent less than 4% of the company's overall rate base.

Morgan Stanley & Co. LLC and Wells Fargo Securities, LLC served as CenterPoint's financial advisors. Latham and Watkins LLP, Phelps Dunbar LLP, and Brunini, Grantham, Grower & Hewes, PLLC served as CenterPoint's legal advisors.

About CenterPoint Energy, Inc.

As the only investor-owned electric and gas utility based in Texas, CenterPoint Energy, Inc. (NYSE: CNP) is an energy delivery company with electric transmission and distribution, power generation and natural gas distribution operations that serve more than 7 million metered customers in Indiana, Louisiana, Minnesota, Mississippi, Ohio and Texas. As of September 30, 2023, the company owned approximately $39 billion in assets. With approximately 8,900 employees, CenterPoint Energy and its predecessor companies have been in business for more than 150 years. For more information, visit www.CenterPointEnergy.com.

About Bernhard Capital Partners

Bernhard Capital Partners is a services and infrastructure-focused private equity management firm established in 2013. Bernhard Capital Partners has deployed capital in four funds across several strategies and has approximately $3.4 billion of gross assets under management. Bernhard Capital Partners seeks to create sustainable value by leveraging its experience in acquiring, operating and growing services and infrastructure businesses. For more information, visit www.BernhardCapital.com.

Use of Non-GAAP Measures

As included in this news release, CenterPoint provides guidance based on non-GAAP income and non-GAAP diluted earnings per share. Generally, a non-GAAP financial measure is a numerical measure of a company's historical or future financial performance that excludes or includes amounts that are not normally excluded or included in the most directly comparable GAAP financial measure.

Management evaluates CenterPoint's financial performance in part based on non-GAAP income and non-GAAP earnings per share. Management believes that presenting these non-GAAP financial measures enhances an investor's understanding of CenterPoint's overall financial performance by providing them with an additional meaningful and relevant comparison of current and anticipated future results across periods. The adjustments made in these non-GAAP financial measures exclude items that management believes do not most accurately reflect the company's fundamental business performance. CenterPoint's non-GAAP income and non-GAAP diluted earnings per share measures should be considered as a supplement to, and not as a substitute for, or superior to, income available to common shareholders and diluted earnings per share, which respectively are the most directly comparable GAAP financial measures. These non-GAAP financial measures also may be different than non-GAAP financial measures used by other companies.

2024 non-GAAP EPS guidance range

- 2024 non-GAAP EPS guidance excludes:
    - Earnings or losses from the change in value of ZENS and related securities; and
    - Gain and impact, including related expenses, associated with mergers and divestitures, such as the Louisiana and Mississippi gas LDC sales.

In providing 2024 non-GAAP EPS guidance, CenterPoint does not consider the items noted above and other potential impacts such as changes in accounting standards, impairments, or other unusual items, which could have a material impact on GAAP reported results for the applicable guidance period. The 2024 non-GAAP EPS guidance ranges also consider assumptions for certain significant variables that may impact earnings, such as customer growth and usage including normal weather, throughput, recovery of capital invested, effective tax rates, financing activities and related interest rates, and regulatory and judicial proceedings. To the extent actual results deviate from these assumptions, the 2024 non-GAAP EPS guidance ranges may not be met, or the projected annual non-GAAP EPS growth rate may change. CenterPoint is unable to present a quantitative reconciliation of forward-looking non-GAAP diluted earnings per share without unreasonable effort because changes in the value of ZENS and related securities, future impairments, and other unusual items are not estimable and are difficult to predict due to various factors outside of management's control.

Forward-Looking Statements

This news release may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this news release are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Current Report, the words "anticipate," "believe," "continue," "could," "estimate," "expect," "forecast," "goal," "intend," "may," "objective," "plan," "potential," "predict," "projection," "should," "target," "will" or other similar words are intended to identify forward-looking statements. These forward-looking statements are based upon assumptions of management which are believed to be reasonable at the time made and are subject to significant risks and uncertainties. Actual events and results may differ materially from those expressed or implied by these forward-looking statements. Forward-looking statements include, but are not limited to, the timing of the closing of the Transaction. Each forward-looking statement contained in this news release speaks only as of the date of this report. Important factors that could cause actual results to differ materially from those indicated by the provided forward-looking information include risks and uncertainties relating to (1) the timing of the expiration or termination of the Hart-Scott-Rodino waiting period and the receipt of any consents, waivers or approvals required to be obtained pursuant to applicable antitrust laws, (2) the occurrence of any event, change or other circumstances that could give rise to the termination of the Transaction or could otherwise cause the failure of the Transaction to close, (3) the risk that a condition to the closing of the Transaction may not be satisfied, including obtaining required regulatory approvals, (4) the outcome of any legal proceedings, regulatory proceedings or enforcement matters that may be instituted relating to the Transaction, (5) the timing to consummate the Transaction, (6) disruption from the Transaction making it more difficult to maintain relationships with customers, employees, regulators or suppliers, (7) the diversion of management time and attention on the Transaction and (8) other factors discussed in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2023 and other reports the Company may file from time to time with the Securities and Exchange Commission.

Contacts

Media:
Media.relations@CenterPointEnergy.com

Investors:
Jackie Richert/Ben Vallejo
Phone: 713.207.6500

Sign In / Register

News Release

<< Back

Feb 24, 2020

CenterPoint Energy Announces Sale of CenterPoint Energy Services Business to Energy Capital Partners

- Sale supports further emphasis on CenterPoint Energy's core utility operations

- ECP to support CES' continued focus on providing the highest level of customer service

- Transaction is expected to close in Second Quarter

HOUSTON, Feb. 24, 2020 /PRNewswire/ -- CenterPoint Energy, Inc. (NYSE: CNP) today announced it has entered into an agreement to sell its natural gas retail business, CenterPoint Energy Services, Inc. (CES) to Energy Capital Partners, LLC, (ECP), a private equity and credit investor specializing in energy infrastructure projects, for total consideration of approximately $400 million, including estimated working capital at close, subject to the satisfaction of customary terms and conditions. As part of the transaction, CES will enter into a structured long-term Preferred Supply agreement where

Shell Energy North America (US), L.P. (SENA) will provide gas supply and collateral support, as well as receive equity warrants. Net proceeds of the sale will be used to repay a portion of outstanding CenterPoint Energy debt.

EnergyCapital Partners

"The sale of our gas retail business further positions CenterPoint Energy to focus on the long-term performance of our core electric and natural gas utility businesses," said John W. Somerhalder II, interim president and chief executive officer of CenterPoint Energy. "At the same time, this sale will strengthen our balance sheet and improve our business risk profile."

Somerhalder added, "When combined with our recent agreement to sell Miller Pipeline and Minnesota Limited, two businesses that comprised our infrastructure services segment, we expect our utility earnings contribution to approach 90% over the next several years."

CES provides competitive natural gas sales, storage and supply, and other energy-related solutions to approximately 30,000 commercial and industrial customers, utilities and municipalities in more than 30 states. CES is headquartered in Houston and has approximately 300 employees.

"ECP looks forward to partnering with CES and its employees in order to continue providing customers with best-in-class service and reliable gas supply," said Andrew Gilbert, a partner at ECP. "We are excited to support CES' future growth."

The sale is anticipated to be completed in the second quarter 2020, subject to the satisfaction of closing conditions, including the expiration or termination of the Hart-Scott-Rodino waiting period.

Goldman Sachs & Co. LLC is serving as exclusive financial advisor to CenterPoint Energy. Akin Gump Strauss Hauer & Feld LLP is acting as legal counsel to CenterPoint Energy. Latham & Watkins, LLP is serving as legal counsel to Energy Capital Partners, LLC and BNP Paribas is providing a committed borrowing base facility.

Headquartered in Houston, CenterPoint Energy, Inc. (NYSE: CNP) is an energy delivery company with regulated utility businesses in eight states and a competitive energy businesses footprint in nearly 40 states. Through its electric transmission & distribution, power generation and natural gas distribution businesses, the company serves more than 7 million metered customers in Arkansas, Indiana, Louisiana, Minnesota, Mississippi, Ohio, Oklahoma and Texas. CenterPoint Energy's competitive energy businesses include natural gas marketing and energy-related services; energy efficiency, sustainability and infrastructure modernization solutions; and construction and repair services for pipeline systems, primarily natural gas. The company also owns 53.7 percent of the common units representing limited partner interests in Enable Midstream Partners, LP, a publicly traded master limited partnership that owns, operates and develops strategically located natural gas and crude oil infrastructure assets. With approximately 14,000 employees and nearly $35 billion in assets, CenterPoint Energy and its predecessor companies have been in business for more than 150 years. For more information, visit CenterPointEnergy.com.

Energy Capital Partners, founded in 2005, is a North American-focused investor across both equity and credit infrastructure assets, including natural gas power generation, renewables and storage solutions, midstream, environmental infrastructure and opportunistic energy situations emphasizing the transition to clean energy while avoiding the more volatile energy subsectors like exploration and production. The ECP team, comprised of 61 people with 600 years of collective industry experience, deep expertise and extensive relationships, has consummated more than 60 transactions over the last 10 years, representing more than $45 billion of enterprise value.

Forward-Looking Statement

The statements in this press release contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this press release are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this press release, the words "anticipate," "believe," "continue," "could," "estimate," "expect," "forecast," "goal," "intend," "may," "objective," "plan," "potential," "predict," "projection," "should," "target," "will" or other similar words are intended to identify forward-looking statements. These forward-looking statements are based upon assumptions of management which are believed to be reasonable at the time made and are subject to significant risks and uncertainties. Actual events and results may differ materially from those expressed or implied by these forward-looking statements. Forward-looking statements include, but are not limited to, statements relating to benefits of the sale, the timing of the closing, CenterPoint Energy's use of proceeds from the sale, the relative contribution of CenterPoint Energy's core energy delivery business after closing, including the related impact to utility earnings percentages, and anticipated changes in CenterPoint Energy's balance sheet, risk profile and earnings quality. Each forward-looking statement contained in this press release speaks only as of the date of this release. Important factors that could cause actual results to differ materially from those indicated by the provided forward-looking information include risks and uncertainties relating to: (1) the timing of the expiration or termination of the Hart-Scott-Rodino waiting period and the receipt of any consents, waivers or approvals required to be obtained pursuant to applicable antitrust laws, (2) the occurrence of any event, change or other circumstances that could give rise to the termination of the proposed transactions or could otherwise cause the failure of the proposed transactions to close, (3) the risk that a condition to the closing of the proposed transactions may not be satisfied, (4) the outcome of any legal proceedings, regulatory proceedings or enforcement matters that may be instituted relating to the proposed transactions, (5) the timing to consummate the proposed transactions, (6) disruption from the proposed transactions making it more difficult to maintain relationships with customers, employees, regulators or suppliers, (7) the diversion of management time and attention on the proposed transactions and (8) other factors discussed in CenterPoint Energy's Annual Report on Form 10-K for the fiscal year ended December 31, 2018, CenterPoint Energy's Quarterly Report on Form 10-Q for the quarters ended March 31, 2019, June 30, 2019 and September 30, 2019 and other reports CenterPoint Energy or its subsidiaries may file from time to time with the Securities and Exchange Commission.

CenterPoint Communications

Natalie Hedde: 812.491.5105

Natalie.hedde@centerpointenergy.com

CenterPoint Investor Relations

David Mordy: 713.207.6284

David.mordy@centerpointenergy.com

View original content to download multimedia:http://www.prnewswire.com/news-releases/centerpoint-energy-announces-sale-of-centerpoint-energy-services-business-to-energy-capital-partners-301009769.html

SOURCE CenterPoint Energy, Inc.

https://www.wsj.com/articles/new-corporate-minimum-tax-could-ensnare-some-firms-over-one-time-moves-260f74df

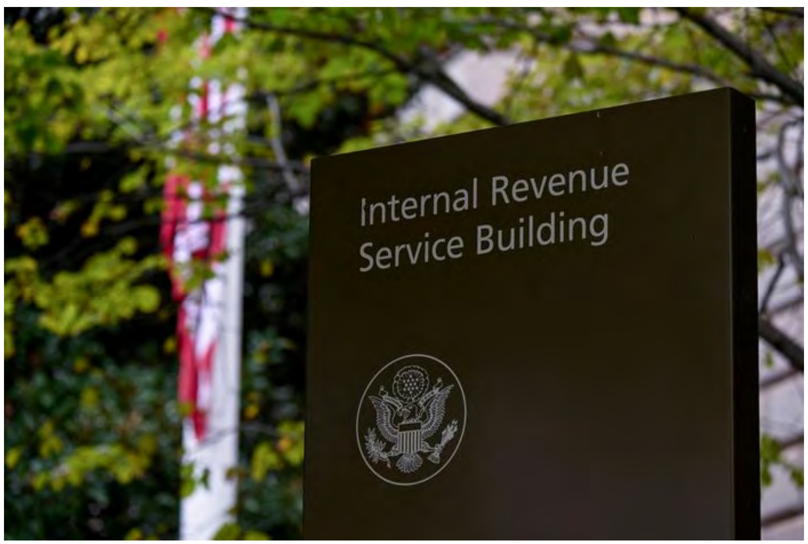
CFO JOURNAL

New Corporate Minimum Tax Could Ensnare Some Firms Over One-Time Moves

Companies including CenterPoint Energy and American Water Works seek government guidance on how the sale of a business unit might trigger the 15% levy

By Jennifer Williams-Alvarez Follow

March 30, 2023 10:00 am ET



The IRS building in Washington. The 15% corporate minimum tax applies to companies that report income averaging at least $1 billion over three years. PHOTO: ERIN SCOTT/REUTERS

A new corporate minimum tax is stoking concern among some companies that one-time activities, such as the sale of a business unit, will push them over the threshold for the levy even though the companies wouldn't otherwise qualify.

The 15% corporate minimum tax that went into effect at the beginning of this year applies to U.S.-based companies that report income to shareholders averaging at least $1 billion over three years. What's more, once a company is subject to the levy, it remains that way even if profits decline unless certain conditions are met, such as a determination from the government that a company shouldn't be subject to the minimum tax.

Some business leaders and companies, such as CenterPoint Energy Inc. and American Water Works Co., are raising the particular problem of so-called extraordinary items in which business segments were sold off and those transactions pushed average profits over the $1 billion mark even though the ongoing businesses aren't above the threshold.

Companies above the $1 billion mark can petition for relief from the minimum tax, said Rohit Kumar, co-leader of the national tax office at accounting firm PricewaterhouseCoopers LLP, but what that process will look like, for now, remains an uncertainty. "There is sort of a 'Hotel California' aspect to this, that once you're an applicable corporation, you're forever an applicable corporation," Mr. Kumar said.

Signed into law last year with the climate, healthcare and tax law called the Inflation Reduction Act, the tax may create complications for buyers and sellers in merger and acquisition transactions, tax advisers say.

The minimum tax requires companies that meet the $1 billion threshold to calculate their taxes with the existing 21% levy on corporate income as currently defined in the tax code and under a 15% rate based on their book, or financial-statement, income. The law stipulates companies pay the higher of the two calculations.

Democrats aimed the provision at large, profitable companies that face relatively low tax burdens. The Joint Committee on Taxation, which provides nonpartisan analysis of tax legislation for Congress, projects the tax will raise a total of about $222 billion over the course of a decade.

The Internal Revenue Service and Treasury Department in late December and in February issued interim guidance on the application of the minimum tax. The earlier guidance addressed issues such as how a spinoff, split-off or carve-out transaction would affect whether a company meets the $1 billion threshold. Uncertainties remain, however, and companies, audit firms and others are watching closely for additional guidance, with some in recent weeks submitting comments urging the government to clarify how extraordinary events will affect the applicability of the tax.

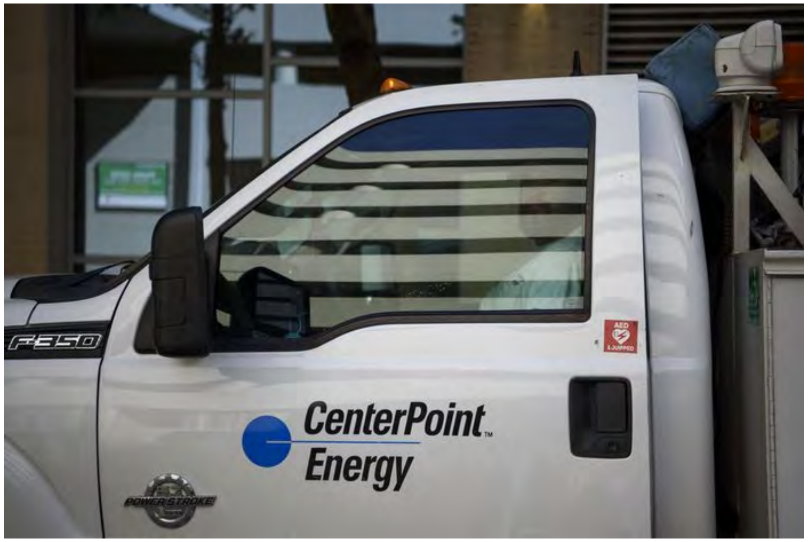
Commenters have asked the government to weigh in on many issues, including how foreign taxes as well as unrealized gains and losses are considered when determining if a company is subject to the tax. Some are also worried that an extraordinary event will bring them within the scope of the levy.

American Water Works in December 2021 sold equity interests of certain subsidiaries for a total of around $1.275 billion, Melissa Ciullo, the company's vice president of tax, said in a March 16 note requesting guidance on the applicability of the tax. That amounted to a pretax gain of $748 million, an "aberration" that significantly increased the company's pretax book income for that year and could "unfairly" subject it to the minimum tax, she said.

This, Ms. Ciullo said, is because there is currently no government guidance that allows the utility to exclude the gain from the sale when determining whether it meets the $1 billion threshold, even though the company was already assessed federal income tax tied to the event.

"Absent further guidance, under the present statutory and administrative guidance, AWW could be unfairly classified as an applicable corporation sooner than when it would be based on its normal, recurring business operations solely due to the one-time, nonrecurring gain," she said.

Electric and natural-gas utility CenterPoint, meanwhile, sold two businesses during the three-year period used to determine the applicability of the minimum tax, from 2020 through 2022. These sales produced substantial book and tax gains—which CenterPoint paid regular corporate income tax on—that would likely subject the company to the minimum tax, CenterPoint said in a March 15 comment.



CenterPoint Energy sold two businesses during the three-year determination period. PHOTO: CALLAGHAN O'HARE/BLOOMBERG NEWS

"While the three-year test may remove a company that realized an unusual earnings spike or suffered a big loss, CenterPoint's experience shows that, in the absence of some additional adjustment, the three-year test is not an effective nor a fair measure to gauge whether a company should be subject to [the minimum tax]," the company said.

The companies are asking the government to exclude extraordinary events such as nonrecurring, one-time sales of businesses when determining whether companies are subject to the minimum tax. CenterPoint Energy and American Water Works declined to comment beyond their responses to the government.

The Treasury Department declined to comment on how it specifically plans to respond to the requests for additional guidance. Forthcoming proposed regulations to implement the tax will provide clarity, a Treasury official said.

The IRS deferred to the Treasury Department when asked to comment on how the government plans to respond to requests for guidance on substantive issues such as extraordinary items.

Some business groups have suggested solutions. The Business Roundtable, in a March 20 comment, said the government could account for atypical income spikes by allowing a company to cut one year off the three-year average, so that two years are used to determine whether the threshold is met. Including a single transaction would be “distortive” if it doesn’t reflect the recurring financials for a company, the group of leaders from some of America’s largest companies said.

Some companies argue that an extraordinary event isn’t a good proxy for the size of the company and shouldn’t be included in calculating whether a company meets the threshold, said Mark Hoffenberg, a principal in the Washington National Tax practice at accounting firm KPMG LLP. Moreover, companies that distribute cash from the sale of a business to shareholders contract in size, he said, which may make it appropriate to reduce financial-statement income for purposes of the threshold test.

But the government hasn’t thus far indicated that they have an appetite for carving out extraordinary events, Mr. Hoffenberg said. “Informally, we’ve heard from government officials, they say, ‘Well yea, we understand there can be extraordinary events, but that’s why we have a three-year averaging rule.’”

Write to Jennifer Williams-Alvarez at jennifer.williams-alvarez@wsj.com

New Corporate Minimum Tax Ushers In Confusion and a Lobbying Blitz

Large companies are bracing for the impact of a 15 percent tax that went into effect this year.

By Alan Rappeport
Alan Rappeport covers the Treasury Department and writes about tax policy.

Sept. 7, 2023

At his State of the Union address this year, President Biden celebrated the fact that his new climate and tax law would no longer allow some of America's largest corporations to pay zero in federal taxes.

"Because of the law I signed, billion-dollar companies have to pay a minimum of 15 percent," Mr. Biden said, referring to the Inflation Reduction Act of 2022. "God love them."

The new corporate minimum tax was one of the most significant changes to the U.S. tax code in decades. Its logic rested on the idea that rich companies should not be able to find loopholes and other accounting maneuvers in order to pay lower tax rates than their workers.

But making the tax operational has become a mammoth challenge for the Biden administration, which has faced intense lobbying from industries that could be on the hook for billions of dollars in new taxes. Those groups have been flooding the Treasury Department with letters asking for lenient interpretations of the law and trying to create new loopholes before their tax bills come due next year. Republican lawmakers have been trying to repeal the law while Democrats such as Senator Elizabeth Warren of Massachusetts have been urging Treasury Secretary Janet L. Yellen to enforce it strictly.

The legislation, which passed with no Republican support, called for the corporate minimum tax to take effect in the 2023 tax year, meaning it will apply to corporate profits earned this year. But the tax was only loosely defined, and Treasury is still writing the rules that will determine how it is carried out.

The corporate minimum tax is entirely separate from the 15 percent “global minimum tax” that the Biden administration brokered with more than 140 nations in 2021. That agreement was aimed at stopping large multinational companies from seeking out tax havens and forcing them to pay more of their income to governments. While the deal is moving ahead in other nations, it continues to face obstacles in the United States, where Congress has been unable to ratify the agreement and allow the United States to comply with the global rules.

But Democrats were able last year to pass a domestic corporate minimum tax, which is a revival of a policy that was last employed in the 1980s. It captures tax revenue from companies that report a profit to shareholders on their financial statements, known as book income, while bulking up on deductions to whittle down their tax bills.

While the corporate tax rate stands at 21 percent, many large companies pay far less than that to the federal government. For years, big companies such as FedEx, Duke Energy and Nike have been able to take advantage of various deductions and tax strategies so that they effectively owe nothing in federal taxes. A 2021 report from the Institute on Taxation and Economic Policy found that 55 of the nation’s largest companies had paid no federal income tax the previous year.

An analysis by the Joint Committee on Taxation last year found that about 150 companies with tax rates below 15 percent would be subject to the new tax. Companies like Amazon and Berkshire Hathaway, which have had effective tax rates in the single digits in recent years, could face the biggest increases in their tax liabilities, according to a summary of research about the impact of the tax published by the Congressional Research Service.

At the Berkshire Hathaway annual meeting in May, Warren E. Buffett, the company's chief executive, acknowledged that there was uncertainty over the new tax but said he did not oppose it.

"We can figure out ways, once we know the rules, where we will pay the 15 percent tax," Mr. Buffett said.

While the tax is aimed at some of the largest companies, smaller businesses have also expressed concern that they could be swept into the new tax regime if the regulations are not sufficiently clarified.

In a comment letter to the Treasury Department and the Internal Revenue Service this year, CenterPoint Energy, a public utility company based in Texas, said it could be unfairly targeted because it had sold part of its gas pipeline and storage operation. Even though CenterPoint paid taxes on the sale, the gains could raise the company's revenue enough to require it to pay additional money under the corporate alternative minimum tax.

"CenterPoint is neither a large corporation nor a corporation that did not pay its fair share but is being subjected to the C.A.M.T. as a result of transactions that reduced its business operations," the company wrote. "The incongruity of the result is striking."

The Treasury Department is expected to release the final rules for the tax before the end of the year. It already made concessions to the insurance industry, which raised concerns that the tax could upend its business model, and told companies that they would not be responsible for making quarterly tax payments related to the new minimum until all the regulations were clarified.

Our business reporters. Times journalists are not allowed to have any direct financial stake in companies they cover.

“Treasury is working to ensure that the biggest and most profitable corporations pay their fair share and that the corporate alternative minimum tax is workable and administrable,” said Ashley Schapitl, a Treasury spokeswoman.

The 15 percent minimum tax applies to corporations that report annual income of more than $1 billion to shareholders but reduced their effective tax rate well below the statutory 21 percent. It was projected to raise over $200 billion over a decade.

Businesses that might face the new tax have been spending heavily to shape its scope and minimize their exposure.

According to Accountable.US, a nonpartisan watchdog group, large financial firms and industry groups representing international conglomerates spent more than $1 million during the first half of this year lobbying Congress over the corporate minimum tax and a 1 percent stock buyback excise tax that was also included in the Inflation Reduction Act. Accountable.US described that as a “significant” amount since Republicans already oppose the provision.

Many sectors are bracing for the tax’s potential impact, but energy companies, the film industry, financial firms and foreign companies that operate in the United States are particularly concerned, according to a review of comment letters submitted to the federal government and corporate filings.

“We’re trying to figure out how to add up apples and oranges, if you will, to make sense of it,” said Nancy McLernon, president and chief executive of the Global Business Alliance, which represents international companies that have U.S. subsidiaries.

Ms. McLernon, whose organization has a working group trying to ensure that the new tax rules can work alongside international accounting standards, lamented that the measure had only made things more complicated for businesses that invested in the United States.

I.R.S. tax forms, which allow for an array of deductions, and financial statements shown to shareholders present different pictures of a company’s performance. Investors use a firm’s book income to get a clearer view of the health of a business; however, some analysts have suggested that companies may soon start to take steps to obscure that measure.

Big businesses that will be hit by the tax are now trying to figure out what kind of income will put them over the $1 billion threshold and what deductions they may be able to keep.

When the legislation passed last year, Senator Kyrsten Sinema of Arizona persuaded her Democratic colleagues to preserve a valuable deduction, known as bonus depreciation, that is associated with purchases of machinery and equipment. Since then, businesses that spend money on repairs and maintenance of their equipment have tried to make the case that those expenses should be included in that carve-out. Other firms, such as film companies, have tried to make the case that the cost of making movies should still be deductible from the new tax.

Despite all the lobbying, most companies are still trying to figure out how the tax will work and how much they need to worry.

"Anybody who is within the scope of the corporate alternative minimum tax has some pretty meaningful unanswered questions," said Pat Brown, co-leader of PwC's Washington National Tax Services practice and a former Treasury official.

Tax and accounting experts have warned for years that this type of corporate minimum tax would not be easy. They contend that it creates a new tax base and has the potential to encourage companies to change how they report their financial income to seek out new loopholes.

William McBride, the vice president of federal tax policy at the Tax Foundation, which has been critical of the new minimum tax, said it had been difficult to set up because it was misguided in the first place. He argued that trying to marry accounting rules and tax laws was a recipe for confusion.

"It's not clear if it's even resolvable in a way that's going to satisfy taxpayers such that they're not stuck with enormous compliance costs," Mr. McBride said.

Efforts to overturn the tax will be fruitless while Mr. Biden is in office, but that hasn't stopped Republican lawmakers from trying.

Backed by lobbyists from the National Association of Manufacturers, the National Mining Association, the U.S. Chamber of Commerce and the Western Energy Alliance, Senate Republicans introduced legislation in May to repeal what they described as a "reckless and complicated" tax that targets job creators.

Alan Rappeport is an economic policy reporter, based in Washington. He covers the Treasury Department and writes about taxes, trade and fiscal matters. He previously worked for The Financial Times and The Economist. More about Alan Rappeport

A version of this article appears in print on , Section B, Page 1 of the New York edition with the headline: Minimum Corporate Tax Is Big Challenge for Biden

Q 3.13: Petitioner's witness Chrissy M. Behme describes Petitioner's proposed implementation of Phase I rates. On page 6, lines 29-30 of her direct testimony, Ms. Behme makes the following statement: "*As described below, revenues and O&M expense will be updated to November 2024, rather than the beginning of the test year*."

a) When Ms. Behme says "November 2024," is she referring to the 12-months ended 10/31/24 or the period ended 11/30/24? Please explain.
b) Please state specifically what 12-month period Petitioner proposes to use for operating revenues and expenses in Phase 1.
c) On page 7, line 20 of her direct testimony, Ms. Behme states that "actual data will be submitted at the time Petitioner files rebuttal." Is Petitioner only proposing to provide actual rate base and capital structure information at the time it files rebuttal? Or will Petitioner also update actual operating results as of 12/31/23?
d) Does the *pro forma* operating net income presented for Phase 1 represent the 12-month forecast ending 12/31/23, 11/30/24, or some other time period? If some other period, state the period used to forecast operating net income for Phase 1.
e) What does Petitioner propose depreciation expense and property tax expense be based upon for Phase I rates – utility plant as of 12/31/23 or some other period? If some other period, state the period proposed and why that period is appropriate.

Response:

a) Ms. Behme is referring to a 12-month period beginning with November 2024 for operating expenses only.
b) Petitioner proposes to use operating revenues for January through December 2025. Operating expenses are for November 2024 through October 2025 with all other expenses presented at January through December 2025. Pro forma depreciation expense is reflected for assets placed in service through December 2023.
c) See Response to OUCC 1.46. Actual operating results will not be updated as of 12/31/23 as calendar year 2023 is not being used to set Phase 1 rates.
d) Pro forma operating net income presented for Phase 1 includes a mixture of two 12-month periods. Operating expense is a 12-month period for November 2024 through October 2025 with all other activity held at January through December 2025.
e) Pro forma depreciation expense is based on assets placed in service through December 2023. Pro forma property tax expense is based on assets placed in service through December 2025.

Q 30.11: On page 7, lines 21 – 26 of her direct testimony, Ms. Behme states

> *…pro forma results of operations at present and proposed rates will be based upon the test year data, but the operating expenses in Phase 1 will begin with November 2024 for the twelve-month period. In addition…certain revenue and expense adjustments will not be included or will not be included at the full amount at Phase 1 because the changes for which these adjustments were made will not occur until the test year.*

a) Please explain what Ms. Behme means by the phrase "pro forma results of operations at present and proposed rates [Phase 1] will be based upon the test year data." How can it be based on test year data if Petitioner is beginning Phase 1 with November 2024?

b) Will Phase 1 operating revenues begin with November 2024 or does Petitioner propose to include test year operating revenues in Phase 1? Please explain.

c) Please list each revenue and expense adjustment that will not be included or will not be included at the full amount at Phase 1, including a description of the adjustment, the amount of the full adjustment, and the amount of the adjustment being excluded from Phase 1.

d) Please explain what Petitioner means by the term "adjustment" as used in her testimony on page 7, lines 24 – 26. Is Ms. Behme referring to adjustments applied to the financial forecast sponsored by Ms. Gray (Unadjusted Test Year) or the adjustments included as Schedules C-3.1 through C-3.39 in Exhibit No. 20?

Response:

a) Because Phase I begins with November 2024. There is only two months of difference from the test year.

b) No, only operation and maintenance expenses will begin with November 2024. Please see the attachments included in CEI South's Response to 45990 OUCC DR06.

c) Please see Petitioner's Exhibit No. 20 and the attachments included in CEI South's Response to 45990 OUCC DR06. Compare Schedule C-3 for Phase 1, Phase 2, and Phase 3 to identify the revenue and expense adjustments for each phase. As explained by CEI South subject matter experts during the tech-to-tech call on January 31, 2024, the differences between the revenue and expense adjustments included at each phase can be identified by comparing the three models. A description of each adjustment is included in Ms. Behme's testimony. Additionally, a description is provided in each adjustment schedule in Petitioner's Exhibit No. 20.

d) Adjustments included in Schedules C-3.1 through C-3.39 in Pet.'s Exhibit No. 20 are the same adjustments applied to the financial forecast sponsored by Ms. Gray (Unadjusted Test Year).

Q 30.6: Please provide the financial forecast model that supports the "Test Year Unadjusted" forecast as reflected throughout Exhibit No. 20, including all workpapers and supporting schedules. Please provide in Excel format with cells unlocked and formulas intact and functional.

Response: The "Test Year Unadjusted" forecast was developed based on the 2025 forecasted needs of CEI South's operational units, including operational areas such as generation, distribution, and high voltage operations. It was not a buildup per se from historical costs because it was based on the forecasted needs for a year that was going to be different than prior years. Operational units forecasted both operational costs and workforce staffing levels necessary for CEI South to run the electric business safely, reliably and effectively during the period the rates are anticipated to be in effect. The forecasted costs include costs for new generation and exclude cost for generation units no longer in service. It also includes a forecast of allocated costs which, as discussed in greater detail in the Direct Testimony of Witness Wood, was developed using escalation for labor while held flat for non-labor expenses.

For direct O&M, the forecasted needs of the operational units were loaded into the accounting and forecasting system utilizing cost objects, which are used to assign FERC accounts. Allocated costs were also loaded into the accounting system. The other components of the forecast, which are based on information provided by others, including margin, fuel, purchased power and capacity purchases, property taxes, depreciation, other income, and an estimated allocation of interest expense and income taxes were also input into the accounting system by cost objects. The system then combines the inputs to generate a CEI South Electric income statement. There are no formulas or spreadsheets that pull together the various inputs to create the Test Year Unadjusted forecast. It is based on a report generated by the accounting system – SAP.

While the forecast for the test year was not developed as a build up from historical costs, it can be compared to historical costs. For example, in Petitioner's Witness Gray's testimony on page 4, there is a waterfall chart that compares 2022 actual pre-tax Operating Income to 2025 Forecasted pre-tax Operating Income and illustrates that the two main variances between the two are (1) a reduction in margin primarily due to a reduction in revenues from the Securitization of the A.B. Brown assets and a reduction in miscellaneous revenues, both of which were partially offset by an increase in revenues from interim recovery mechanisms; and (2) a reduction in O&M which is primarily due to the retirement of the A.B. Brown coal units and the termination of the Joint Operating Agreement for Warrick Unit 4.

On page 5 of Ms. Gray's Direct Testimony, there is a second waterfall chart that compares 2022 actual O&M (excluding pass through mechanisms) to 2025 forecasted O&M (also excluding pass through mechanisms). It shows the decreased forecast O&M in 2025 is primarily due to the generation operational unit area, which is further discussed in the Direct Testimony of Witness Bradford.