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November 1, 2024

VIA ELECTRONIC MAIL (clerkofcouncil@nola.gov)
Clerk of Council
City Hall, Room 1E09
1300 Perdido Street
New Orleans, LA 70112

Re: Joint Application of Delta States Utilities NO, LLC and Entergy New Orleans, LLC Authorizing Delta States Utilities NO, LLC to Operate as a Jurisdictional Natural Gas Local Distributions Company, CNO Docket UD-24-01
KM File No. 33965-1

Dear Clerk of Council:

Enclosed for electronic filing in the above referenced docket is the Post-Hearing Reply Brief of Delta States Utilities NO, LLC ("DSU NO"). As confirmed with your office, the requisite original and number of hard copies are not mandatory to formalize this filing in the docket.

Should you have any questions regarding the above, please do not hesitate to contact me. Thank you for your assistance with this matter.

Very truly yours,

C. R. T.

Carrie R. Tournillon

CRT:tp
Enclosures
cc: Official Service List UD-24-01 (via e-mail)

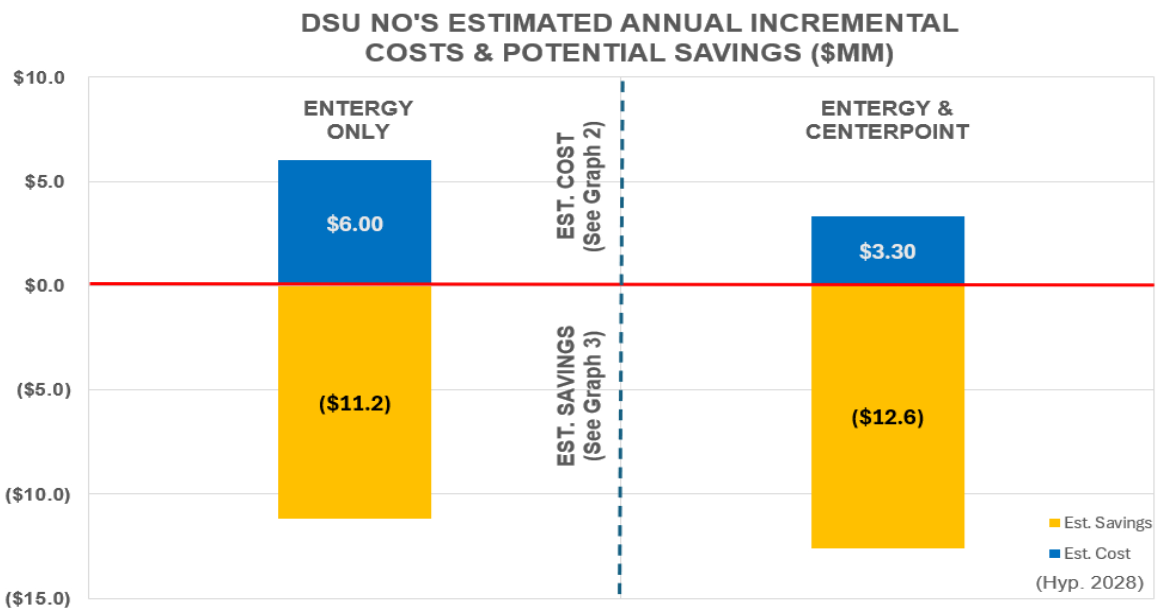
BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

DELTA STATES UTILITIES NO, LLC ENTERGY NEW ORLEANS, LLC AND, EX PARTE. **IN RE: APPLICATION FOR AUTHORITY TO OPERATE AS LOCAL DISTRIBUTION COMPANY AND INCUR INDEBTEDNESS AND JOINT APPLICATION FOR APPROVAL OF TRANSFER AND ACQUISITION OF LOCAL DISTRIBUTION COMPANY ASSETS AND RELATED RELIEF.**	**))))))))))))**	**DOCKET NO. UD-24-01**

DELTA STATES UTILITIES NO, LLC REPLY BRIEF

Graph No. 1



BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

DELTA STATES UTILITIES NO, LLC ENTERGY NEW ORLEANS, LLC AND, EX PARTE. **IN RE: APPLICATION FOR AUTHORITY TO OPERATE AS LOCAL DISTRIBUTION COMPANY AND INCUR INDEBTEDNESS AND JOINT APPLICATION FOR APPROVAL OF TRANSFER AND ACQUISITION OF LOCAL DISTRIBUTION COMPANY ASSETS AND RELATED RELIEF.**	**))))))))))))**	**DOCKET NO. UD-24-01**

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DELTA STATES UTILITIES NO, LLC REPLY BRIEF

The takeaway from the evidence in this proceeding should be the acquisition of Entergy New Orleans, LLC ("ENO") gas assets ("Gas Business") by Delta States Utilities NO, LLC ("DSU NO") ("Transaction") is a rare opportunity the Council of the City of New Orleans ("Council") and its residents, *who are gas customers of ENO*, should embrace. As the graph on the cover of this reply brief depicts, the Transaction provides the opportunity for significant ratemaking benefits to gas customers in the City of New Orleans, even prior to considering the millions in economic impact stemming from basing a new $1.7 billion multi-state utility in New Orleans. At a minimum, the Transaction results in no net harm and clearly demonstrates opportunities for benefits in excess of cost when both benefits and costs are considered in an impact analysis. ***However, the Advisors analysis is one sided and only presents the costs of the Transaction without any reflection of benefits and savings that serve to mitigate such costs.***

The Advisors Original Brief continues to paint a negative picture of the Transaction by overstating cost impacts, particularly the impact on an *unrealistic* 50 ccf per month residential customer, which is *two times more* gas per month than ENO's actual residential gas customers on average. In addition, the rate impact is inflated because the Advisors allocate 64% of the costs to residential customers, despite residential customers being responsible only for about 35% of total gas sales. ***These two issues alone overestimate the impact on residential customers by more than 250%,***[1] which is prior to (i) correcting for other issues that overstate the revenue requirement impact and (ii) consideration of rate benefits to be realized by gas customers from the costs.

Further, the Advisors have attempted to discredit benefits of DSU NO's Transition Plan Costs, including DSU NO's implementation of a cloud-based information technology ("IT") system, by ignoring evidence in the record supporting the need for and benefits of moving from a 2005 on-premises system that is currently used to provide service to gas customers to a modern, cloud-based IT system that DSU NO would implement as part of its Transition Plan. Likewise, the Advisors have refused to recognize the benefits of DSU NO operating as a standalone natural gas utility with its core-focus consolidated gas business forecasted to result in significant customer savings over current operations.

In addition, the Advisors' recommendation for a mitigation framework would also severely limit the scope of benefits that DSU NO can use in a future rate case in support of recovery of its IT and other Transition Plan Costs. Such an overly limiting position on the use of qualitative benefits, studies and forecasts to support net benefits of a

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[1] *See infra,* at Graph No. 2.

transformational IT project is inconsistent with the Advisors' positions, and the Council's conclusions, in prior utility proceedings - - such as approval of ENO's investment and recovery of $75 million in advanced metering infrastructure ("AMI")[2] and approval for ENO to join and continue to participate in the Midcontinent Independent System Operator, Inc. ("MISO").[3]

Notably, in its Initial Brief, the Sewer and Water Board of New Orleans ("SWBNO") agreed with DSU NO that it is reasonable and appropriate, *and consistent with Council precedent*, for all benefits to be considered and weighed against costs. The SWBNO indicated:[4]

> Further, SWBNO agrees with the Applicants that all benefits (quantifiable and hard-to-quantify/ qualitative) and harms of the Gas Transaction should be considered and weighed against each other. ***This is routinely done in change-of-ownership regulatory proceedings, including proceedings before the City Council***.

The Advisors' grossly overestimated ratepayer impact analysis that focuses only on cost without regard to benefits and their limitations on DSU NO's ability to support benefits in the future is not consistent with the Council's 18-factor public interest analysis set forth in Resolution No. R-06-88 ("Restructuring Resolution") that explicitly refers to *forecasted* short and long term benefits (among many other public interest factors),[5] its

[2] Docket No. UD-16-04, *Application of Entergy New Orleans, Inc. for Approval to Deploy Advanced Metering Infrastructure, and Request for Cost Recovery and Related Relief*, Resolution and Order No. R-18-37 (February 8, 2018) ("*AMI Resolution and Order*").

[3] Docket No. UD-17-02, *Application of Entergy New Orleans, Inc. for Approval Regarding Continued Participation in the Midcontinent Independent System Operator, Inc. Regional Transmission Organization*, Resolution and Order No. R-17-627 (December 14, 2017) ("*MISO Resolution and Order*").

[4] SWBNO Initial Brief at 9 (October 15, 2024) (emphasis added).

[5] Restructuring Resolution at Factor "e".

plenary authority to regulate utilities, and its broad public policy responsibilities that go beyond a gas rate when considering what is in the best interest of the public.

Separate from the Advisors concerning positions, the Alliance for Affordable Energy ("AAE") intervened in this proceeding in an attempt to deprive New Orleans residents from the option of using natural gas in their homes - - without their knowledge or sign off. The AAE seeks to turn this proceeding into a municipalization / electrification docket that eliminates residential customers' option for gas appliances and would significantly increase their energy burden.[6] Retrofits alone for a typical, existing natural gas residence costs between $17,400 and $31,700;[7] electrification would also increase the average annual utility cost per household by more than $1,100 for space and water heating.[8] However, AAE gave zero consideration to the cost impact on customers and the City of New Orleans as a result of its extreme proposals for drastic changes to the provision of natural gas service.

<u>Moreover, there is no evidence that the AAE's position in this proceeding represents the desire of the residents of the City of New Orleans.</u> Evidence in this proceeding only supports the harm that would come to New Orleans residents - - particularly *<u>low-income</u>* gas customers - - from AAE recommendation to require all residential customers to give up their access to natural gas in their homes, which results

[6] Hearing Exhibit DSU NO – 15, Rebuttal Testimony (Public Redacted) of David E. Dismukes, Ph.D., at 60:5-13 (June 28, 2024) (as corrected July 17, 2024).

[7] Hearing Exhibit DSU NO – 15, Rebuttal Testimony (Public Redacted) of David E. Dismukes, Ph.D., at 60:16-17 (June 28, 2024) (ask corrected July 17, 2024), citing Rosen Consulting Group, New York Building Electrification and Decarbonization Costs, 2022, p. 1.

[8] Hearing Exhibit DSU NO – 15, Rebuttal Testimony (Public Redacted) of David E. Dismukes, Ph.D., at 61:6-9 (June 28, 2024) (ask corrected July 17, 2024).

in a significant increase in annual utility costs severely impacting low-income gas customers. Thus, the AAE recommendations should be completely disregarded.

This Transaction provides an opportunity to the Council, the New Orleans gas customers, the City of New Orleans, and the residents of New Orleans. As discussed in detail in DSU NO's Initial Brief, the opportunities for these stakeholders include:

- Service provided by a New Orleans based natural gas utility with much more gas customers than the existing owner (approximately 600,000 customers vs 200,000 customers) and the economies of scale and efficiencies associated with a gas focused operator.
- A new corporation setting up its headquarters in New Orleans and bringing more jobs to the City.
- The impact of suppliers and service providers (e.g., Accenture) locating more of their employees and business operations to New Orleans to work with the DU corporate headquarters.
- DSU NO is transforming the gas business by implementing a cloud-based technology platform and is targeting Day 1 efficiencies in the DSU NO business resulting in expected operational savings.
- There is no rate increase to DSU NO customers requested in this filing; the Council will have the opportunity to make decisions associated with any future rate impacts in the initial rate case to be filed no sooner than 15 months post-Closing, putting the risk on DSU NO for cost recovery.

DSU NO urges the Council to recognize ***all*** of the benefits expected to result from the proposed Transaction to ***all*** stakeholders - - gas ratepayers and New Orleans citizens alike - - and approve the Transaction inclusive of the relief requested in the Joint Application of DSU NO and ENO dated December 11, 2023, and the significant number of commitments that DSU NO has agreed to memorialize as conditions of approval.[9]

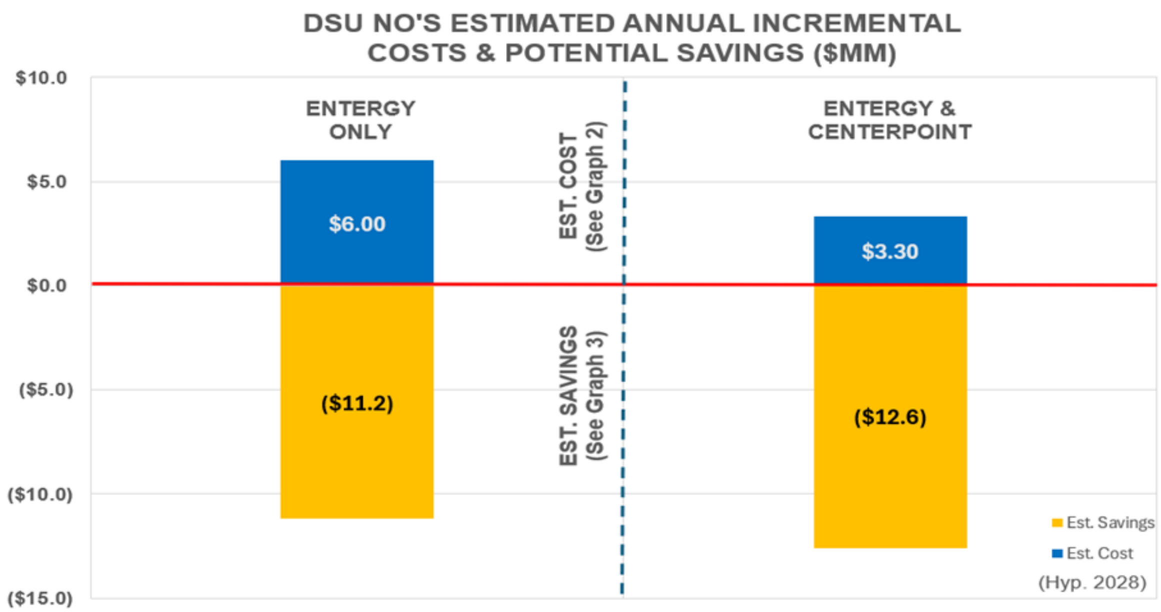
[9] DSU NO Initial Brief at Exhibit C (October 15, 2024).

I. RESPONSE TO ADVISORS INCORRECT, CONFUSING, AND/OR CONFLICTING STATEMENTS

In its Original Brief, the Advisors make several statements that are incorrect, confusing, and/or conflicting when considering all of the evidence in the record. DSU NO's responses to these statements are summarized in **Exhibit A** to this reply brief.

Notably, the Advisors continue to present an overstated hypothetical impact analysis that (i) does not accurately reflect information in the record that reduces their cost impact of the Transaction and (2) does not reflect any benefits of the Transaction. When these issues are corrected and the Transaction is presented holistically with costs and benefits represented, the Transaction, at a minimum, presents no net harm to gas customers and has the potential for a significant upside for customers as shown below.

Graph No. 1[10]



[10] The estimated annual incremental costs and savings components in Graph No. 1 are detailed in Graph No. 2 (costs) and Graph No. 3 (savings), with evidentiary support for each discussed within this Reply Brief.

Notably, the significant quantified rate benefits of the Transaction presented by DSU NO in evidence in this proceeding have been excluded from the analysis provided by the Advisors,[11] including (i) lower forecasted O&M growth of $10 million (CY 2026 estimate),[12] (ii) IT O&M efficiencies of $1.2 million in 2028 alone[13] (and $1.7 million on average per year over the 2028-2052 period),[14] and (iii) shared services O&M savings from combined Entergy and CenterPoint transactions of up to 10% or approximately $1.4 million on annual revenue requirement savings.[15] These are benefits quantified by DSU NO in evidence in this proceeding and total estimated annual savings of $11.2 million (Entergy only) and $12.3 (Entergy and CenterPoint combined), as reflected in Graph No. 1; however these savings are not factored into the Advisors' cost-only impact analysis and claim of $16.5 million in "quantifiable net ratepayer harm."

Further, the Advisors continue to ignore hard to quantify and qualitative benefits of the cloud-based IT system, including scalability as evidenced by benefits to gas customers from economies of scale expected from the CenterPoint transaction. As discussed herein, such positions are inconsistent with past positions of the Advisors and Council. Moreover, the Advisors continue to urge the Council to adopt a mitigation

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[11] Hearing Exhibit ADV-11, Direct Testimony (HSPM-CS) of Byron S. Watson, Advisors witness, at 45:9-46:6 and Table 3 (May 31, 2024). All factors considered by Mr. Watsons are cost impacts.

[12] Hearing Exhibit DSU NO – 8, Rebuttal Testimony (HSPM-CS) of Brian K. Little, DSU NO witness, at 24:3-8 (June 28, 2024).

[13] Hearing Exhibit DSU NO-17, Rebuttal Testimony (HSPM-CS) of David E. Dismukes, Ph.D., DSU NO witness, at Exhibit DED-5 (CBA), Tab "O&M Benefits."

[14] Hearing Exhibit DSU NO-17, Rebuttal Testimony (HSPM-CS) of David E. Dismukes, Ph.D., DSU NO witness, at Exhibit DED-5 (CBA), Tab "O&M Benefits." *See also*, Advisors Original Brief at 35-36 (October 15, 2024).

[15] Hearing Exhibit DSU NO – 6, Rebuttal Testimony (Public Redacted) of Brian K. Little, DSU NO witness, at 24:9-13 (June 28, 2024); Hearing Exhibit DSU NO - 15, Rebuttal Testimony (Public Redacted), DSU NO witness, at 6:18-19 (June 28, 2024) (as corrected July 17, 2024). See also for $1.4 million: HSPM-CS DSU NO Response to CNO 1-8, Attachment A (Cited in Advisors Testimony) at Tab "DSU NO O&M Forecast ENO" (sum of F10:F17 X 10% = $1.4 million).

framework that unfairly restricts DSU NO's ability to demonstrate Transaction benefits that result in customer savings.

DSU NO responds to these concerns with the Advisors brief, as follows:

A. Advisors Hypothetical Rate Impact Analysis Inflates Customer Impact

Advisors criticize DSU NO for not providing a bill impact estimate related to the Transaction in this proceeding and only providing one in response to their direct testimony.[16] However, that is because DSU NO has not requested to change rates in this proceeding.[17] ***This proceeding is not a rate case but a proceeding to determine whether the sale of ENO's gas assets to DSU NO is in the public interest.***[18] DSU NO only responded to the Advisors rate impact analysis with its own hypothetical incremental revenue requirement estimate because it was necessary to correct the inaccurate and highly overstated results that the Advisors put forth in their analysis.[19]

To be clear, DSU NO has only sought to defer its Transition Plan Costs to a regulatory asset for future consideration by the Council not sooner than 15 months post-Closing,[20] which is approximately *two years* from now, when more information is available to evaluate the cost and benefits of the Transition Plan. This means that (i) gas customers will have rate consistency for a two- to three-year period, and (ii) any potential future

[16] Advisors Original Brief at 15 (October 15, 2024).

[17] Delta States Utilities No, LLC And Entergy New Orleans, LLC, *ex parte*. *In Re: Application For Authority to Operate as Local Distribution Company and Incur Indebtedness and Joint Application For Approval Of Transfer And Acquisition Of Local Distribution Company Assets And Related Relief*, Docket No. UD-24-01 (December 11, 2023) ("Joint Application"). *See* Joint Application at page 3 (December 11, 2024).

[18] *See* Joint Application at 25 (December 11, 2023).

[19] Hearing Exhibit DSU NO – 15, Rebuttal Testimony (Public Redacted) of David E. Dismukes, Ph.D., DSU NO witness, at 4:16-5:21 (June 28, 2024) (as corrected July 17, 2024).

[20] Hearing Exhibit DSU NO – 3, Direct Testimony of Brian K. Little, DSU NO witness, at 29:11-30:11 (December 11, 2023).

impact from the Transaction on DSU NO gas rates would be subject to the Council's broad authority to evaluate the prudence of the Transition Plan Costs and set rates that are just and reasonable for gas customers.

The Advisors acknowledge that a rate impact analysis cannot be done until more information is available to the Council,[21] which is why DSU NO has proposed to maintain consistent rates until accurate costs and savings can be accurately demonstrated to the Council in a holistic and comprehensive manner. DSU remains at risk for these costs and the ultimate outcome of the future filing, which incentivizes DSU NO to achieve as much benefit to the customers as possible. The proper forum to address any potential rate impact is when a rate impact is proposed for Council approval, which is not in this proceeding, and which would occur when actual historical test year data is available to determine the actual impact, if any.

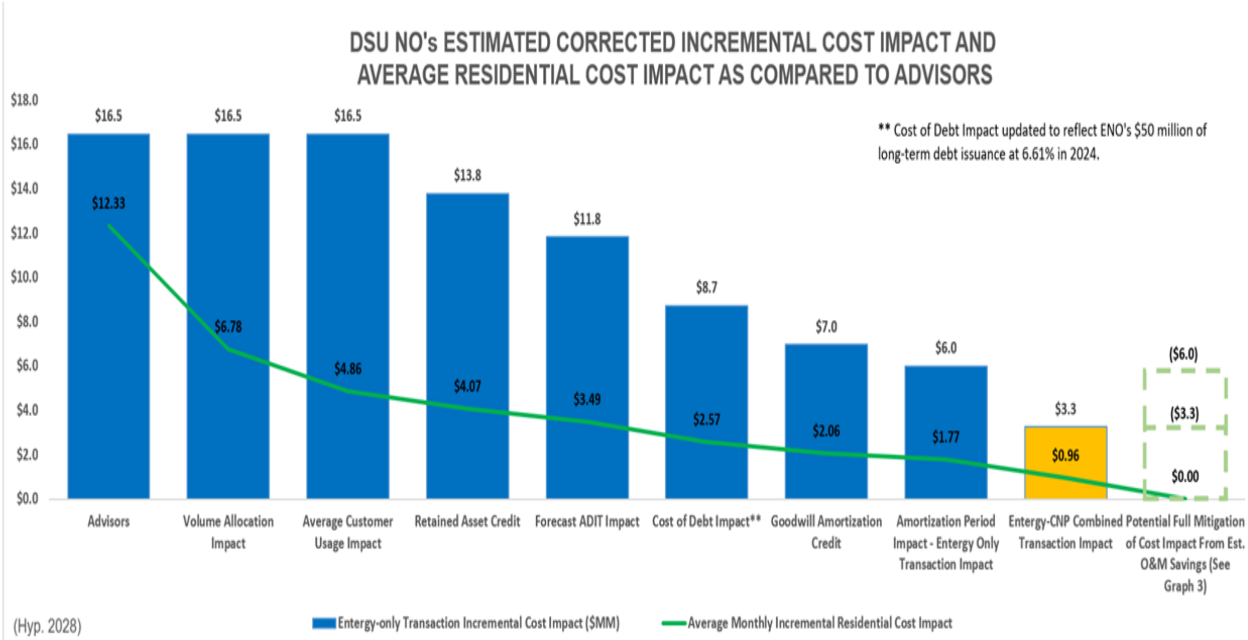
Yet, the Advisors continue to assert their impact assessment is reasonable and reliable,[22] negatively portraying the Transaction to the public and Council. The Advisors' impact analysis is not only hypothetical, but it is also inaccurate.

The Advisors' estimated cost impact overstates the forecasted cost impact of the Transaction on gas customers, which again is only one side of a net impact analysis. Residential class allocation and "typical" customer monthly usage magnify the impact on a residential customer by more than 250%, as discussed in subparts A.1 and A.1 below. As demonstrated in DSU NO's testimonies, and depicted below, both the incremental revenue requirement and residential bill impact of the Advisors are significantly higher

[21] DSU NO Initial Brief, at 72 (October 15, 2024).
[22] Advisors Original Brief at 15-17 (October 15, 2024).

than reasonable to estimate a bill impact, particularly when the estimated savings achieved by those costs fail to be considered.

Graph No. 2[23]



Key inputs of the Advisors incremental revenue requirement assessment specific to the Transaction requiring correction include (i) Retained Asset credit, (ii) forecasted accumulated deferred income tax ("ADIT") impact and crediting of goodwill, (iii) cost of debt impact, and (iv) amortization period for Transition Plan Cost recovery.[24] Further, determining a realistic residential bill impact requires correction of (i) the allocation of the incremental revenue requirement to the residential customer class and (ii) the assumed

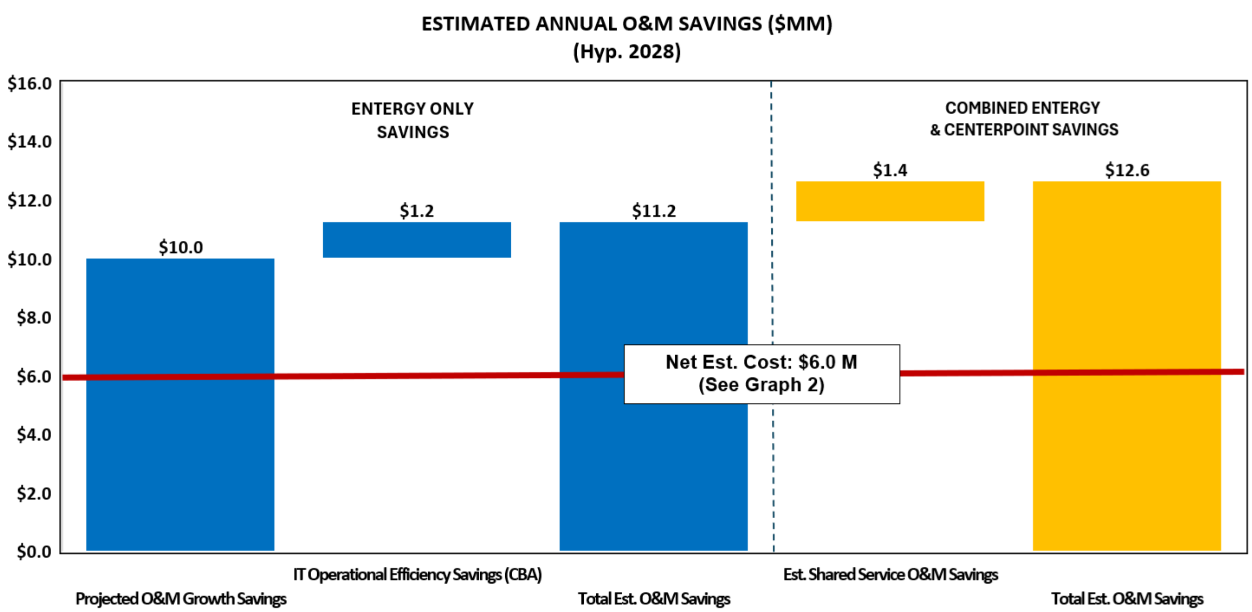
[23] Graph No. 2 to this Reply Brief presents corrections to the Advisors cost impact analysis as performed by Dr. Dismukes in Rebuttal Testimony (Hearing Exhibit DSU NO-17 at Exhibit DED-1) but using a 6.61% cost of debt (Hearing Exhibit ADV – 12, Watson Surrebuttal Testimony at 25:5-9) and 100% sharing of goodwill amortization credit. Evidentiary support for the individual components of the graph are discussed within this Reply Brief.

[24] Hearing Exhibit DSU NO – 15, Rebuttal Testimony of David E. Dismukes, Ph.D., DSU NO witness, at 4:16 – 5:11 (June 28, 2024). (as corrected July 17, 2024).

customer monthly usage.[25] As discussed herein, each of these key hypothetical variables (among others) that comprise the advisors best guess of bill impact approximately *three years* from now has been factually disputed numerous times within the record and/or has been determined to be better resolved by the parties in the future rate proceeding.

Most importantly, for an actual net impact assessment, estimated benefits must also be considered, which the Advisors have excluded from their analysis. DSU NO has demonstrated projected "ratemaking" savings to gas customers from the Transaction in the context of only the Entergy Transaction and the combined Entergy and CenterPoint transactions, as shown below:

Graph No. 3[26]



When a corrected cost impact of the Transaction is considered with quantified benefits of the Transaction, the Transaction clearly does not result in "quantifiable net

[25] Hearing Exhibit DSU NO – 15, Rebuttal Testimony of David E. Dismukes, Ph.D., DSU NO witness, at 5:12-21 (June 28, 2024). (as corrected July 17, 2024).

[26] Components of Graph No. 3 are discussed with evidentiary support within this Reply Brief.

ratepayer harm" as alleged by the Advisors, and instead presents the opportunity for significant benefits, as shown in Graph No. 1, even before considering hard-to-quantify benefits, qualitative benefits and economic benefits of the Transaction.

As discussed in DSU NO's Initial Brief and in response to the Advisors in this Reply Brief, the Advisors *cost* impact assessment and customer *cost* impact assessment (which are the impacts prior to consideration of benefits) contain inaccuracies based on the evidence in the record of this proceeding, which includes evidence presented in response to errors in the Advisors direct testimony and quantified benefits supported by DSU NO in testimony. As a result, the Advisors' Transaction cost impact and customer cost impact analyses are inaccurate and confusing to the public and the Council.

1. Volume Allocation Impact - Advisors Class Allocation Methodology is Inconsistent with Data and Requirement for DSU NO to Commit to Cost-of-Service Studies

The Advisors recommend conditioning approval of the Transaction on DSU NO committing to perform several cost-of-service studies as part of its initial rate filing, including: (i) a retail class cost of service study,[27] (ii) a cost of service study of the "non-jurisdictional" gas customer contracts,[28] and (iii) a cost of service study relating to transportation of gas to the New Orleans Power Station.[29] Further, the Advisors have requested DSU NO to commit to implementing rates that are consistent with cost-of-service principles.[30] Yet, the Advisors insist on using a residential class allocator that allocates to residential customer costs that are representative of nearly double the volume

[27] Advisors Original Brief at 20-21 (October 15, 2024).
[28] Advisors Original Brief at 20-21 (October 15, 2024).
[29] Advisors Original Brief at 21 (October 15, 2024).
[30] Advisors Original Brief at 20-21 (October 15, 2024).

of gas consumed by the residential customer class (64% versus 35%).[31] Considering the Advisors have proposed to condition approval of the Transaction on DSU NO conducting a new cost of service analysis for reallocation of costs based on cost of service principles, it is inconsistent for the Advisors to use non-cost of service principles for evaluating cost impacts of the Transaction - - particularly given that any cost impact from the Transaction would not affect customer rates until proper allocations are determined in accordance with cost-of-service principles. Thus, *for purposes of calculating a reasonable and reliable customer cost impact estimate of the Transaction (ie., an estimate that does not yet reflect benefits)*, it is unreasonable to use a class allocator that significantly over-allocates costs to the residential class simply because that is what is used by ENO in its formula rate plan. If the Advisors consider a 64% allocation of cost to the residential customer class reasonable, despite sales to residential customers only comprising about 35% of total ENO gas sales, then why require DSU NO to commit to undertaking cost-of-service studies or setting rates consistent with cost-of-service principles?

The Advisors dispute DSU NO's using an allocation methodology that spreads costs based on the volume of gas that customers actually use because it has not been approved by the Council.[32] However, DSU NO submits that continuing to implement an allocation methodology that will no longer be approved by the Council at the time of the future rate case, based on the Advisors conditions agreed to by DSU NO, does not result in a reasonable or reliable impact assessment *for the Council's purposes in this*

[31] Hearing Exhibit DSU NO – 15, Rebuttal Testimony (Public Redacted) of David E. Dismukes, Ph.D., DSU NO witness, at 30:14-17 (June 28, 2024) (as corrected July 17, 2024), citing ENO 2022 Volumes and Customers, EIA Form 176.

[32] Advisors Original Brief at 16 (October 15, 2024).

proceeding as it overstates the customer cost impact on residential customers. When using the Advisors' overstated hypothetical incremental cost revenue requirement increase of $16.5 million and correcting only for the change in class revenue allocation to make it reflective of actual class volumes, from 63.5% (per Advisors) to 34.9% (2022 historical actual usage by residential customers), the residential bill impact drops from **$12.33 to $6.78**.[33]

2. Average Customer Usage Impact - Advisors Residential Customer Usage is Inconsistent with Actual Historical Data and Unreasonable to Use

The Advisors' stated "typical residential gas customer" cost impact is anything but typical for a residential gas customer and thus is not helpful in presenting the impact of the Transaction to the public or the Council. Rather, the Advisors' "typical residential gas customer" impact is confusing and paints an inaccurate and negative picture of the Transaction and should not be relied on by the Council in its consideration of whether the Transaction is in the public interest and whether any conditions or mitigation is needed.

The Advisors' residential gas customer impact analysis uses 50 ccf per month as the customer's typical gas volume usage.[34] However, based on actual historical data, the typical ENO gas customer only uses on average 27 ccf per month.[35] As a result of using

[33] *See* Graph No. 2 to this Reply Brief, which presents the corrections to the Advisors cost impact analysis as performed by Dr. Dismukes in Rebuttal Testimony (Hearing Exhibit DSU NO-17 at Exhibit DED-1) but using a 6.61% cost of debt (Hearing Exhibit ADV – 12, Watson Surrebuttal Testimony at 25:5-9) and 100% sharing of goodwill amortization credit.

[34] Advisors Original Brief at 37, footnote 48 (October 15, 2024).

[35] ENO 2022 Volumes and Customers, EIA Form 176.

a higher monthly volume, the customer cost impact is also higher under the Advisors analysis than it would be for the average consumption of an actual ENO gas customer.[36]

For example, Advisors customer cost impact numbers would result in DSU NO over-collecting more than $4.5 million in annual revenues from the residential class for Transition Plan Costs - - $15.2 million instead of $10.7 million, based on:

- Advisors use 64% allocation to the residential class of their estimated $16.5 million incremental annual revenue requirement;
- The 64% allocation results in residentials being responsible for $10.6 million of the $16.5 million estimated by the Advisors as the incremental revenue requirement cost impact of the Transaction;
- *However*, the Advisors' $12.33 per month incremental bill impact from the Transaction X 12 months X 103,000 residential customers = $15.2 million in revenues, or over $4.5 million more than the residential class's share.

Simply put, it is not realistic to use 50 ccf per month for determining a residential customer cost impact from the Transaction. Such significantly overstated customer cost impact estimate is not helpful to the Council's evaluation of whether the Transaction is in the public interest, is confusing to the customers considering it is not based on any relevant customer usage, and should be disregarded.

The Advisors claim that using 50 ccf usage per month is appropriate for a customer cost impact analysis because that is what has been used in practice for estimating a "typical residential gas customer" bill impact.[37] However, 50 ccf usage per month is nearly twice as much as what an actual residential gas customer uses on average.[38] Thus, how

[36] Hearing Exhibit DSU NO – 17, Rebuttal Testimony (HSPM-CS) of David E. Dismukes, Ph.D., DSU NO witness, at 33:3-7 (June 28, 2024) (as corrected July 17, 2024).

[37] Hearing Exhibit ADV – 9, Direct Testimony of Byron S. Watson (Public Redacted), Advisors witness, at 37:11-17 (May 31, 2024).

[38] Hearing Exhibit DSU NO – 18, Rejoinder Testimony of David E. Dismukes, Ph.D., DSU NO witness, at 39:5-9 (September 3, 2024).

is using 50 ccf helpful to the Council in evaluating the impact of the Transaction and whether it is in the public interest? DSU NO submits it is not.

Using a monthly usage that is not realistic for the average gas customer to estimate the customer cost impact of the Transaction does not provide transparency to customers of the actual estimated impacts relevant to their actual monthly bills. And as a result, customers following the Transaction will be confused that the estimated impact is relevant to the average customers' bill.

For example, as Dr. Dismukes testified, representing "typical residential monthly impact" as something other than a 12-month average defeats the purpose of the analysis and results in the Council receiving information that is arbitrarily inflated, not indicative of real-world annual ratepayer impacts, and not representative of a 'typical residential monthly impact.[39] Dr. Dismukes testified this would be akin to estimating an electric customer's "typical residential monthly impact" based solely on summer bills - - which is not done:[40]

> **Q. WHAT IS YOUR RESPONSE TO THE ADVISORS' ARGUMENT THAT 50 CCF/MONTH IS INDICATIVE OF REAL-WORLD RATEPAYER IMPACTS?**
>
> A. It is a truism that residential ratepayers in New Orleans consume more natural gas during winter heating months, just like most residential ratepayers in New Orleans consume more electricity during hot and humid summer months. The obvious implication of a "typical residential monthly impact" is that this represents the average of peak and off-peak seasons and this average multiplied by 12 months would represent an average annual residential ratepayer impact. *Representing a "typical residential monthly impact" otherwise, or as based on peak usage, would defeat the*

[39] Hearing Exhibit DSU NO – 18, Rejoinder Testimony of David E. Dismukes, Ph.D., DSU NO witness, at 39:10 – 40:4 (September 3, 2024) emphasis added).

[40] Hearing Exhibit DSU NO – 18, Rejoinder Testimony of David E. Dismukes, Ph.D., DSU NO witness, at 39:10 – 40:4 (September 3, 2024) (emphasis added, internal cites omitted).

> *purpose of the analysis and result in providing information to the Council that is* ***arbitrarily inflated*****,** ***not indicative of real-world annual ratepayer impacts*** *and certainly* ***not representative of a "typical residential monthly impact."*** For example, if this were not true, ENO Electric rate increases could be evaluated based solely on summer bills; yet, *ENO estimates monthly rate impacts based on a typical customer consuming 1,000 kWh per month, which is very similar to ENO Electric's actual 2022 average residential monthly consumption of 1,049.4 kWh per month*.

Inaccurate and confusing data should not be used just because that is how it has been done. The Advisors' "typical residential gas customer" cost impact only represents the impact of the Transaction on a fictitious customer that is not relevant to the average ENO gas customer. When you further correct the Advisors estimate to address both the class allocation issue and customer usage issue, the residential customer impact is reduced from **$12.33 to $4.86**, *a* **$7.47 decrease** based on these two factors alone,[41] demonstrating these assumptions magnify the rate impact by more than 250%.

3. Overstated Revenue Requirement Impact – Advisors do not correct for errors that inflate estimated cost impact of Transaction

Notably, the Advisors' incremental revenue requirement is based only on information available at the time of their direct testimony (May 31, 2024), and thus has not been updated with information provided by DSU NO in its rebuttal testimony,[42] even though the Advisors have acknowledged DSU NO's positions on two key inputs that cause the Advisors revenue requirement impact to be overstated and agreed that such

[41] *See* Graph No. 2 to this Reply Brief, which presents the corrections to the Advisors cost impact analysis as performed by Dr. Dismukes in Rebuttal Testimony (Hearing Exhibit DSU NO-17 at Exhibit DED-1) but using a 6.61% cost of debt (Hearing Exhibit ADV – 12, Watson Surrebuttal Testimony at 25:5-9) and 100% sharing of goodwill amortization credit.

[42] Advisors Original Brief at 16 (October 15, 2024).

inputs would be more accurately determined in a future rate case.[43] Those two key inputs include ADIT impact and cost of debt impact. In addition, other key inputs remain subject to dispute - - such as the appropriate depreciation or amortization period for recovery of Transition Plan Costs (through a regulatory asset and/or Intangible Plant), and the Retained Asset credit to be applied to determine the net revenue requirement impact to gas customers due to DSU NO's recovery of its share of Transition Plan Costs.

a. Retain Asset Credit

The Advisors continue to represent in their Original Brief that the Transaction will result in a $16.5 million revenue requirement impact.[44] However, the Advisors have continued to understate the assets in ENO's gas rate base that DSU NO will be replacing and that should be netted against Transition Plan Costs through the Retained Asset credit. Specifically, the Advisors ignore that DSU NO has already accounted for the costs to replace facilities used by the Gas Business that are being retained by ENO.[45] Although DSU NO will initially lease certain replacement facilities (which cost will be reflected in its O&M expense),[46] the ENO facilities are still assets in ENO's current rate base being

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[43] Hearing Exhibit ADV – 12, Surrebuttal Testimony of Byron S. Watson (Public Redacted), Advisors witness, at 18:3-13 (August 5, 2024).

[44] Advisors Original Brief at 2 (October 15, 2024).

[45] Hearing Exhibit ADV-11, Direct Testimony (HSPM-CS) of Byron S. Watson, Advisors witness, at 45 (Table 3) and 43:6-10 (May 31, 2024). The $16.5 million cost impact does not reflect the full Retained Asset credit provided in Hearing Exhibit DSU NO-17, HSPM CS Rebuttal Testimony of David E. Dismukes, Ph.D., at Exhibit DED-3, Tab "Shared Assets," cell C29 (September 3, 2024); and Hearing Exhibit DSU-11, Rejoinder Testimony (HSPM-CS) of Brian K. Little, DSU NO witness, at 5:6 – 6:8 (September 3, 2024).

[46] Hearing Exhibit DSU NO – 3, Direct Testimony of Brian K. Little, DSU NO witness, at 10:19-26 (December 11, 2023); *see also*, Hearing Exhibit DSU NO-6, Rebuttal Testimony (Public Redacted) of Brian K. Little, DSU NO witness, at 26:11-27:2 (June 28, 2024), citing Hearing Exhibit DSU NO-8, Rebuttal Testimony (HSPM-CS) of Brian K. Little, DSU NO witness, at Exhibit BL-10 (Tab "DSU Other Adjustments") (June 28, 2024).

retained by ENO.[47] Thus, the Retained Asset credit used to net against DSU NO's Transition Plan Costs in calculating an incremental revenue requirement impact should include the entire ENO facility Retained Assets amount. However, the Advisors have reduced the Retained Asset credit to eliminate the facility assets, thereby inflating the estimated incremental revenue requirement associated with the Transaction.[48] Applying the full Retained Asset amount as a credit reduces the Advisors cost impact estimate by **$2.7 million**, and further reduces the customer cost impact by $0.79.[49]

b. Forecast ADIT Impact and Goodwill Amortization Credit

The Advisors have acknowledged that DSU NO will create ADIT prior to any rate impact to customers as part of its initial rate case, which will offset the impact of ENO's net ADIT balance not transferring to DSU NO at closing.[50] Yet, the Advisors have not properly reflected new ADIT as an offset to the ADIT impact in their estimated incremental revenue requirement analysis.[51]

Importantly, the mitigation that the new ADIT creates, among other mitigations, is enhanced by DSU NO's proposals and commitments in this proceeding. For example,

[47] Hearing Exhibit DSU NO – 3, Direct Testimony of Brian K. Little, DSU NO witness, at 10:19-11:4 (December 11, 2023); *see also*, Hearing Exhibit DSU NO – 6, Rebuttal Testimony (Public Redacted) of Brian K. Little, DSU NO witness, at 26:11-27:2 (June 28, 2024).

[48] Hearing Exhibit ADV-11, Direct Testimony (HSPM-CS) of Byron S. Watson, Advisors witness, at 45 (Table 3) and 43:6-10 (May 31, 2024). The $16.5 million cost impact does not reflect the full Retained Asset credit. *See* Hearing Exhibit DSU NO – 17, HSPM CS Rebuttal Testimony of David E. Dismukes, Ph.D., at Exhibit DED-3, Tab "Shared Assets," cell C29 (September 3, 2024).

[49] *See* Graph No. 2 to this Reply Brief, which presents the corrections to the Advisors cost impact analysis as performed by Dr. Dismukes in Rebuttal Testimony (Hearing Exhibit DSU NO-17 at Exhibit DED-1) but using a 6.61% cost of debt (Hearing Exhibit ADV – 12, Watson Surrebuttal Testimony at 25:5-9) and 100% sharing of goodwill amortization credit.

[50] Hearing Exhibit ADV – 12, Surrebuttal Testimony of Byron S. Watson (Public Redacted), Advisors witness, at 19:5 – 20:15 (August 5, 2024).

[51] Hearing Exhibit ADV – 14, Surrebuttal Testimony of Byron S. Watson (HSPM-CS), Advisors witness, at 18:3 – 21:7 (August 5, 2024).

DSU NO has committed to adopting ENO rates at Closing - - rates which reflect a lower rate base from the ADIT offset - - resulting in DSU NO foregoing revenue requirement during the first two to three years post-Closing to provide time for DSU NO to establish its own replacement ADIT,[52] and without any rate impact to customers. DSU NO witness Mr. Jay Lewis has estimated that the revenue requirement change caused by the net effect of changes in ADIT decreases by roughly one-third before new rates are expected to be in effect; thus, DSU NO's commitment to adopt ENO's rates, rate schedules and riders at Closing eliminates approximately one-third of the net rate effect from the loss of ENO's net ADIT balance.[53]

Further, DSU NO has proposed for Transition Plan Costs to be deferred to a regulatory asset with an extended 25-year amortization period, which serves to enhance the production of ADIT during this extended period.[54] New ADIT established by DSU NO will serve to offset impact on customers from the loss of ENO's net ADIT balance.[55] Thus, this is not a $58 million rate base issue as the Advisors suggest in their Original Brief.[56]

Moreover, an ADIT impact will be eliminated over time because of increases in DSU NO's net ADIT balance and changes that otherwise would have occurred to ENO's ADIT balance in the normal course of business;[57] and in the interim, the revenue

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[52] Hearing Exhibit DSU NO – 15, Rebuttal Testimony (Public Redacted) of David E. Dismukes, Ph.D., DSU NO witness, at 18:20 – 19:5 (June 28, 2024) (as corrected July 17, 2024).

[53] Hearing Exhibit DSU NO – 12, Rebuttal Testimony (Public Redacted) of Jay A. Lewis, DSU NO witness, at 21 (June 28, 2024).

[54] Hearing Exhibit DSU NO – 12, Rebuttal Testimony (Public Redacted) of Jay A. Lewis, DSU NO witness, at 21 (June 28, 2024).

[55] Hearing Exhibit DSU NO – 12, Rebuttal Testimony (Public Redacted) of Jay A. Lewis, DSU NO witness, at 18 (June 28, 2024).

[56] Advisors Original Brief at 10-11 (October 15, 2024).

[57] Hearing Exhibit DSU NO – 12, Rebuttal Testimony (Public Redacted) of Jay A. Lewis, DSU NO witness, at 9-12 (June 28, 2024).

requirement impact will be offset through DSU NO's commitment not to recover the goodwill it records as a result of the Transaction and to share with customers the resulting goodwill tax credit.[58] Notably, the goodwill tax credit would amount to approximately an **$1.7 million annual credit** to DSU NO's revenue requirement if shared 100% with customers.[59]

Yet, despite acknowledging the ADIT offsets and benefits of DSU NO proposed approaches in testimony, the Advisors' continue to present in their Original Brief a revenue requirement cost impact that does not properly reflect these offsets and mitigations.[60] Once accounting for DSU NO's adoption of ENO's rates for a two-to-three year period, the creation of new ADIT established by DSU NO, and sharing 100% of goodwill tax benefits with customers, and prior to considering the benefits of an extended 25-year amortization period, the Advisors estimated cost impact revenue requirement is

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[58] Hearing Exhibit DSU NO – 12, Rebuttal Testimony (Public Redacted) of Jay A. Lewis, DSU NO witness, at 15-16 and 18 (June 28, 2024). As discussed in Exhibit A to this Reply Brief, the Advisors refer to the goodwill benefit as a credit to rate base; however, DSU NO has indicated that it will not seek recovery of the goodwill, which when combined with the amortization of that goodwill for tax purposes will result in tax deductions related to goodwill, and DSU NO is open to sharing with customers a portion of this tax benefit to further mitigate the *net revenue requirement impacts* of ENO ADIT not transferring at closing. *See* Hearing Exhibit DSU NO-12, Rebuttal Testimony (Public Redacted) of Jay Lewis, DSU NO witness, at 15-16 (June 28, 2024).

[59] The Advisors' maximum goodwill credit in their Original Brief at 11 understates the amount of goodwill to be created from the Transaction because the Advisors are taking the purchase price less ENO's NBV without removing the Retained Assets. *See* Hearing Exhibit ADV-12, Surrebuttal Testimony (HSPM-CS) of Byron S. Watson, Advisors witness, at 33:6-14 (August 5, 2024). The Advisors previously acknowledged Retained Assets should be removed. *See* Hearing Exhibit ADV-11, Direct Testimony (HSPM-CS) of Byron S. Watson, Advisors witness, at 46:18-47:5 (May 31, 2024). Further, the Advisors credit is not grossed up for tax purposes. When these issues are corrected, the estimated annual goodwill amortization credit to revenue requirement is $1.7 million.

[60] Advisors Original Brief at 12, citing Ex. ADV-9 (Watson Direct) at 46 (October 15, 2024).

reduced by **$3.6 million annually** and the Advisors estimated customer impact is further reduced by $1.09.[61]

c. Cost of Debt Impact

The Advisors revenue requirement impact also reflects the difference in DSU NO's anticipated cost of debt at closing and ENO's historical cost of debt, which is not appropriate.[62] As the Advisors have acknowledged, ENO recently issued new debt in May 2024 at a rate approximately 200 basis points higher than ENO's average cost of long-term debt prior to that issuance.[63] Thus, even ENO cannot issue debt at the same low rates as it was able to do under prior market conditions.

Further, DSU NO's cost of debt is not due to credit issues. DSU NO has a strong indicative 'BBB' credit rating,[64] which is more favorable than ENO's, providing a long-term benefit to customers.[65] Yet, DSU NO's anticipated long-term debt rates are higher than the one averaged across all of ENO's current issuances.[66] However, this higher cost of debt is simply a reflection of market conditions at the time the debt was priced and is not a reflection of the relative financing positions, or financial risks, between DSU NO and

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[61] *See* Graph No. 2 to this Reply Brief, which presents the corrections to the Advisors cost impact analysis as performed by Dr. Dismukes in Rebuttal Testimony (Hearing Exhibit DSU NO-17 at Exhibit DED-1) but using a 6.61% cost of debt (Hearing Exhibit ADV – 12, Watson Surrebuttal Testimony at 25:5-9) and 100% sharing of goodwill amortization credit.

[62] Hearing Exhibit ADV – 3, Direct Testimony of Joseph W. Rogers (HSPM-CS), Advisors witness, at 34:18-35:8 (May 31, 2024).

[63] Hearing Exhibit DSU NO- 17, Rebuttal Testimony (HSPM-CS) of David E. Dismukes, Ph.D., DSU NO witness, at DED-3, Tab ENO 2023 FRP (June 28, 2024) (as corrected July 17, 2024), and Hearing Exhibit ADV-12, Surrebuttal Testimony of Byron S. Watson (Public Redacted) at 23:4 – 25:9 (August 5, 2024). Prior to the May 2024 issuance, ENO's average cost of long-term debt was 4.75%.

[64] See DSU NO Response to CNO 1-24 (Cited in Advisors' Testimony).

[65] Hearing Exhibit ENO – 4, Rebuttal Testimony (Public Redacted) of Alyssa Maurice-Anderson, ENO witness, at 11:1-12:5 (June 28, 2024).

[66] Hearing Exhibit DSU NO – 17, Rebuttal Testimony (HSPM-CS) of David E. Dismukes, Ph.D., DSU NO witness, at 20:1-8 (June 28, 2024) (as corrected July 17, 2024).

ENO.[67] Nor is it due to any non-arm's length transaction.[68] Further, going forward, in a scenario when each company is pursuing long-term debt financing, the Advisors have indicated that gas customers could even benefit from DSU NO's credit rating as compared to ENO's.[69]

Thus, as Dr. Dismukes has testified, the cost of debt impact analysis should compare the cost of DSU NO debt based on market conditions at the time it was priced, and not a comparison of DSU NO's debt rate to the debt costs associated with ENO's operations.[70] While DSU NO and the Advisors may not agree on the cost differential for determining a cost of debt impact, Advisors' witness Mr. Watson seemed to acknowledge in his surrebuttal testimony that at a minimum, the comparison would not be DSU NO's cost of debt to ENO's weighted average historical cost of long-term debt (prior to the 2024 debt issuance) but to the cost of more recent ENO debt issuances reflecting current market conditions.[71]

Still further, DSU NO has acknowledged per the Advisors' request that the Council has the authority to set a hypothetical cost of debt for DSU NO for ratemaking purposes.[72] Thus the actual impact of DSU NO's cost of debt cannot be determined until the future

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[67] Hearing Exhibit DSU NO – 15, Rebuttal Testimony (Public Redacted) of David E. Dismukes, Ph.D., DSU NO witness, at 20:12-21:2 (June 28, 2024) (as corrected July 17, 2024).

[68] Hearing Exhibit DSU NO – 4, Rebuttal Testimony (Public Redacted) of Jeffrey Yuknis, DSU NO witness, at Exhibit JY-3 (June 28, 2024).

[69] Hearing Exhibit DSU NO – 15, Rebuttal Testimony (Public Redacted) of David E. Dismukes, Ph.D., DSU NO witness, at 22:16-23:3 (June 28, 2024) (as corrected July 17, 2024).

[70] Hearing Exhibit DSU NO – 18, Rejoinder Testimony of David E. Dismukes, Ph.D., DSU NO witness, at 36:16-18 (September 3, 2024).

[71] Hearing Exhibit ADV-12, Surrebuttal Testimony of Byron S. Watson (Public Redacted) at 25:5-7 (August 5, 2024).

[72] Hearing Exhibit DSU NO – 4, Rebuttal Testimony (Public Redacted) of Jeffrey Yuknis, DSU NO witness, at Exhibit JY-2, Section B., No. 5 (June 28, 2024).

rate case when the Council determines DSU NO's cost of debt and weighted average cost of capital to be used for ratemaking purposes.

Yet, in its Original Brief, the Advisors' continue to present a revenue requirement impact that calculates the cost of debt impact by comparing DSU NO's cost of debt to ENO's low historical cost of debt, thereby overstating the impact.[73] As with the ADIT impact, it is important to keep in mind that any cost of debt impact would not affect customers until the Council authorizes DSU NO's cost of debt in the future rate case and determines just and reasonable rates for DSU NO to charge, which would not happen until about three years from now. When comparing to the most recent ENO debt issuance, the Advisors cost estimate of revenue requirement would decrease by **$3.1 million** and the estimated rate impact would further decrease by $0.92.[74]

d. Transition Cost Amortization Impact

DSU NO requested to defer Transition Plan Costs to a regulatory asset for future recovery and proposed to amortize the regulatory asset over 25 years to mitigate the impact on ratepayers by reducing the annual revenue requirement impact,[75] and in recognition that the cloud-based IT environment being implemented by DSU NO is dissimilar to past IT investments made by ENO, which could justify a different depreciable life for those costs.[76] The Advisors have argued for booking certain IT and facilities costs

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[73] Advisors Original Brief at 12, citing Ex. ADV-9 (Watson Direct) at 46 (October 15, 2024).

[74] *See* Graph No. 2 to this Reply Brief, which presents the corrections to the Advisors cost impact analysis as performed by Dr. Dismukes in Rebuttal Testimony (Hearing Exhibit DSU NO-17 at Exhibit DED-1) but using a 6.61% cost of debt (Hearing Exhibit ADV – 12, Watson Surrebuttal Testimony at 25:5-9) and 100% sharing of goodwill amortization credit.

[75] Hearing Exhibit DSU NO – 12, Rebuttal Testimony (Public Redacted) of Jay A. Lewis, DSU NO witness, at 15 (June 28, 2024).

[76] Hearing Exhibit DSU NO-14, Rejoinder Testimony of Jay A. Lewis, DSU NO witness at 7:9-12 (September 3, 2024).

in FERC Account 303 (Intangible Plant) and depreciating over 15 years because that is the depreciation period and useful life used by ENO for its on-premises IT system.[77] However, the cloud-based IT environment being implemented by DSU NO is dissimilar to past IT investments made by ENO, which could justify a different depreciable life for those costs, which discussion is better suited for DSU NO's initial rate filing.[78]

The SWBNO supports DSU NO's proposal to defer Transition Plan Costs to a regulatory asset and amortize over a 25-year period, indicating that DSU NO's plan is more reasonable than the Advisors' plan to book certain costs to Intangible Plant.[79] The SWBNO indicated, "Stretching out the amortization of Transition Costs would lower the rate impact for ratepayers and should allow Delta States to take advantage of ADIT that it would not be able to do with a 15-year depreciation schedule."[80] However, the SWBNO also agreed with DSU NO witness Mr. Jay Lewis that the period for recovery of Transition Plan Costs can (and likely should) be addressed by the Council in the future rate case.[81]

Despite this uncertainty in a key input that will influence the impact of Transition Plan Costs on DSU NO's annual revenue requirement and a customer's bill, the Advisors have continued to present an impact analysis that uses the shorter depreciation period -- an approach SWBNO has called less reasonable than DSU NO's plan - - in support of its claim that the Transaction will result in "quantifiable net ratepayer harm."[82] By

[77] Hearing Exhibit ADV-12, Surrebuttal Testimony of Byron S. Watson (Public Redacted) at 5:2-16 and 16:1-18:2 (August 5, 2024).

[78] Hearing Exhibit DSU NO – 14, Rejoinder Testimony of Jay A. Lewis, DSU NO witness at 7:9-12 (September 3, 2024).

[79] SWBNO Initial Post-Hearing Brief at 19-20 (October 15, 2024).

[80] SWBNO Initial Post-Hearing Brief at 19-20 (October 15, 2024).

[81] SWBNO Initial Post-Hearing Brief at 22 (October 15, 2024).

[82] Advisors Original Brief at 15-17 (October 15, 2024).

continuing to use a 15-year depreciation period, without any recognition that DSU NO has agreed to a longer deprecation or amortization period, the Advisors impact analysis is designed in a way most negative to the Transaction. Applying the DSU NO proposed extended amortization period would reduce the Advisors' cost estimate revenue requirement by **$1.0 million** and further reduce the estimated rate impact by $0.29.

4. Correcting Advisors Analysis Results in Significantly Smaller Incremental Revenue Requirement and Customer Cost Impact

As previously presented in Graph No. 2 (above), when the ADIT impact, depreciation/amortization period, and Retained Asset credit are corrected,[83] sharing of goodwill tax credits added,[84] and the cost of debt impact is reduced to reflect current market conditions rather than ENO's historical low debt costs,[85] the Advisors incremental revenue requirement impact is reduced from **$16.5 million to $6.0 million**.[86] Importantly, this does not fully correct for cost of debt and instead bases the cost of debt impact on ENO's most recent debt issuance cost of 6.61%.[87]

Further, when these corrections are made, the cost impact of the Transaction on a residential customer's bill is significantly reduced and would result in a $1.77 per month estimated impact, significantly less than the $12.33 per customer per month quoted by

[83] Dismukes Rebuttal at Exhibit DED-1 at Tab DED-1 p. 1 (June 28, 2024) (as corrected July 17, 2024).

[84] Hearing Exhibit DSU NO – 12, Rebuttal Testimony (Public Redacted) of Jay A. Lewis, DSU NO witness, at 15-16 (June 28, 2024).

[85] Hearing Exhibit ADV – 12, Surrebuttal Testimony of Byron S. Watson (Public-Redacted), Advisors witness, at 25:5-9 (August 5, 20240.

[86] *See* Graph No. 2 to this Reply Brief, which presents the corrections to the Advisors cost impact analysis as performed by Dr. Dismukes in Rebuttal Testimony (Hearing Exhibit DSU NO-17 at Exhibit DED-1) but using a 6.61% cost of debt (Hearing Exhibit ADV – 12, Watson Surrebuttal Testimony at 25:5-9) and 100% sharing of goodwill amortization credit.

[87] Hearing Exhibit ADV – 12, Surrebuttal Testimony of Byron S. Watson (Public-Redacted), Advisors witness, at 25:5-9 (August 5, 20240.

the Advisors. This is prior to consideration of benefits/savings to customers from Transition Plan Costs.

Moreover, as also shown in Graph No. 2 (above), when the economies of scale from the CenterPoint transaction are considered, the cost impact decreases to **$3.3 million** and customer cost impact to $0.96 - - prior to considering the benefits to be realized by ratepayers from those costs, such as a moder, cloud-based IT system and core-focused natural gas utility.

B. Transaction Impact Should Reflect Costs AND BENEFITS

If the Council is going to consider costs and rate impacts of the Transaction in this proceeding - - despite DSU NO not seeking a rate change - - DSU NO respectfully urges the Council to evaluate the Transaction using realistic assumptions and a holistic evaluation inclusive of estimated benefits, so that the estimated impact is not overstated to portray the Transaction in a negative light. As previously discussed, the easily quantifiable benefits include lower forecasted O&M growth, IT-specific O&M efficiencies, and for the combined CenterPoint and Entergy transactions, savings in shared services expenses, such that (as depicted below), the benefits of the Transaction *at a minimum* support that the Transaction would result in a no net harm for gas customers. And, the benefits of the Transaction provide significant upside potential, as the Transaction is more likely to result in significant ratemaking benefits to gas customers - - prior to considering qualitative benefits, economic benefits and additional benefits from the CenterPoint and Entergy combined transactions. *See* Graph No. 3.

However, as discussed above, the Advisors have refused to reflect these benefits in the Transaction impact analysis and are proposing a very restricting framework for consideration of benefits in the future rate case proceeding to support DSU NO's recovery of Transition Plan Costs.

1. Advisors Fail to Recognize Important Ratemaking Benefits of the Transaction

The Advisors claim that the Transaction will result in "quantifiable net ratepayer harm."[88] However, such is an unavoidable result when the Advisors do not include any ratepayer benefits in their impact analysis. Not including both benefits and costs creates a one-sided impact analysis and in turn portrays the Transaction in a negative light, which is confusing to the Council and public. When adjusting the incremental revenue requirement analysis to include only a portion of the rate related benefits of the Transaction (*e.g.*, the quantified benefits discussed below), the Transaction, at a minimum, presents a net no harm to ratepayers, with a significant upside for ratepayer and economic benefits, as shown in Graph No. 3.

a. Savings Quantified to Date by DSU NO in Costs-Benefits Graph

As demonstrated by DSU NO in evidence and reflected in DSU NO's cost-benefits graph (Graph No. 1 to this reply brief), the Transaction will provide ratepayer benefits quantified by DSU NO in this proceeding. These include:

Lower Forecasted O&M Growth: ENO's O&M's expense has historically increased at more than 8.5% CAGR; whereas, DSU NO expects its O&M expense to increase at inflation.[89] Comparatively, this results in O&M savings forecasted to be in excess of **$10**

[88] Advisors Original Brief at 14 (October 15, 2024).

[89] Hearing Exhibit DSU NO - 11, Rebuttal Testimony (HSPM-CS) of Brian K. Little, DSU NO witness, at Exhibit BL-10 (June 28, 2024).

million annually by the time the first rate case is implemented.[90] Notably, the Advisors' estimated rate impact analysis does not include this benefit.

Cost Benefit Analysis ("CBA"): DSU NO's CBA supports benefits specific to implementation of the cloud-based IT system. As DSU NO explained in testimony, DSU NO intentionally used a very narrow set of benefits in the CBA to be conservative, focusing on O&M efficiencies and economic benefits specifically from the IT system.[91] However, just considering IT O&M efficiencies results in approximately $1.7 million in savings on average per year over the period 2028 to 2052.[92] In their Original Brief, the Advisors support this factoring into the Council's analysis of factor "(e)" but they did not include it in their cost impact analysis.[93] To be conservative, DSU NO only has included **$1.2 million in IT O&M efficiencies** for purposes of Graphs 1 and 3 in this Reply Brief, based on its estimated savings for CY 2028 alone.[94]

Reduced O&M Expense from Shared Services: The combined Entergy and CenterPoint Transactions will result in a consolidated gas platform serving 600,000 customers instead of 200,000. This is estimated to result in a reduction in ENO shared services O&M costs of up to 10%, or **$1.4 million per year**.[95]

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[90] Hearing Exhibit DSU NO - 11, Rebuttal Testimony (HSPM-CS) of Brian K. Little, DSU NO witness, at Exhibit BL-10 (June 28, 2024).

[91] Hearing Exhibit DSU NO – 15, Rebuttal Testimony (Public Redacted) of David E. Dismukes, Ph.D., DSU NO witness, at 8:8-12 (June 28, 2024) (as corrected July 17, 2024).

[92] Hearing Exhibit DSU NO – 17, Rebuttal Testimony (HSPM-CS) of David E. Dismukes, Ph.D., at DED-5, Tab "O&M Benefit" [(G8+G32)/25] (June 28, 2024) (as corrected July 17, 2024). See also, Advisors HSPM-CS Original Brief at 35-36 (October 15, 2024).

[93] Advisors Original Brief (HSPM-CS) at 35-36 (October 15, 2024).

Hearing Exhibit DSU NO-17, Rebuttal Testimony (HSPM-CS) of David E. Dismukes, Ph.D., DSU NO witness, at Exhibit DED-5 (CBA), Tab "O&M Benefits.

[95] Hearing Exhibit DSU NO – 4, Rebuttal Testimony (Public Redacted) of Jeffrey Yuknis, DSU NO witness, at 14 and Exhibit JY-1 (June 28, 2024); Hearing Exhibit DSU NO – 15, Rebuttal Testimony (Public

b. Other Quantifiable Benefits Not Included in Costs-Benefits Graph

The limited set of benefits quantified by DSU NO and included in its costs-benefits graph (Graph No. 1) is a conservative estimate of benefits as other significant benefits can be reasonably expected from the Transaction and implementation of a transformational IT platforms.

__Total Cost of Ownership ("TCO")__: DSU NO has presented evidence from its technology Integration Partner, Accenture International Limited ("Accenture"), that under a TCO analysis, the cloud-based IT system will provide savings of 22% over 10 years when compared to expected costs of ENO platform. The TCO analysis is another means of estimating benefits that considers a broader set of benefits than those included in the CBA, such as savings in fixed costs.[96]

__More Favorable Credit Rating__: DSU NO has received an indicated credit rating of 'BBB' from Standard & Poor's.[97] As recognized by the Advisors in testimony, DSU NO's 'BBB' indicative rating is more favorable than ENO's current credit rating, which (i) may provide DSU NO with more favorable access to lower cost debt should DSU NO access long-term debt markets, (ii) may justify a lower return on equity than that which would otherwise be approved for ENO, and (iii) when combined, would result in a lower weighted average cost of capital to benefit of ratepayers.[98] Yet, while the Advisors included

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Redacted) of David E. Dismukes, Ph.D., DSU NO witness, at 6:18-19 (June 28, 2024) (as corrected July 17, 2024). See also for $1.4 million: HSPM-CS DSU NO Response to CNO 1-8, Attachment A (Cited in Advisors Testimony) at Tab "DSU NO O&M Forecast ENO" (sum of F10:F17 X 10% = $1.4 million).

[96] Hearing Exhibit DSU NO – 9, Rejoinder Testimony (Public Redacted) of Brian K. Little, DSU NO witness, at 7:8-20 (September 3, 2024); Hearing Exhibit DSU NO – 6, Rebuttal Testimony (Public Redacted) of Brian K. Little, DSU NO witness, at Exhibit BL-11 (June 28, 2024).

[97] See DSU NO Response to CNO 1-24 (Cited in Advisors' Testimony).

[98] Hearing Exhibit ADV-1, Direct Testimony of Mr. Joseph W. Rogers (Public Redacted), Advisors witness, at 24:1-10.

estimated negative impacts (*e.g.,* ADIT impact), they did not include an estimate of this potential benefit.

Continued Expected Synergies and Efficiencies: Benefits of the cloud-based IT system should not just be retrospective. An important benefit of a cloud-based system is its scalability that will continue to create synergies and efficiencies in the future.[99] A perfect example is the CenterPoint transaction. As previously discussed, the CenterPoint transaction alone would result in reduced incremental revenue requirement for ENO customers of $2.7 million (reflecting costs only) and create shared service O&M savings of up to 10%, or $1.4 million per year in addition to the approximately $11.2 million in annual savings from lower forecasted O&M growth and IT O&M efficiencies.[100]

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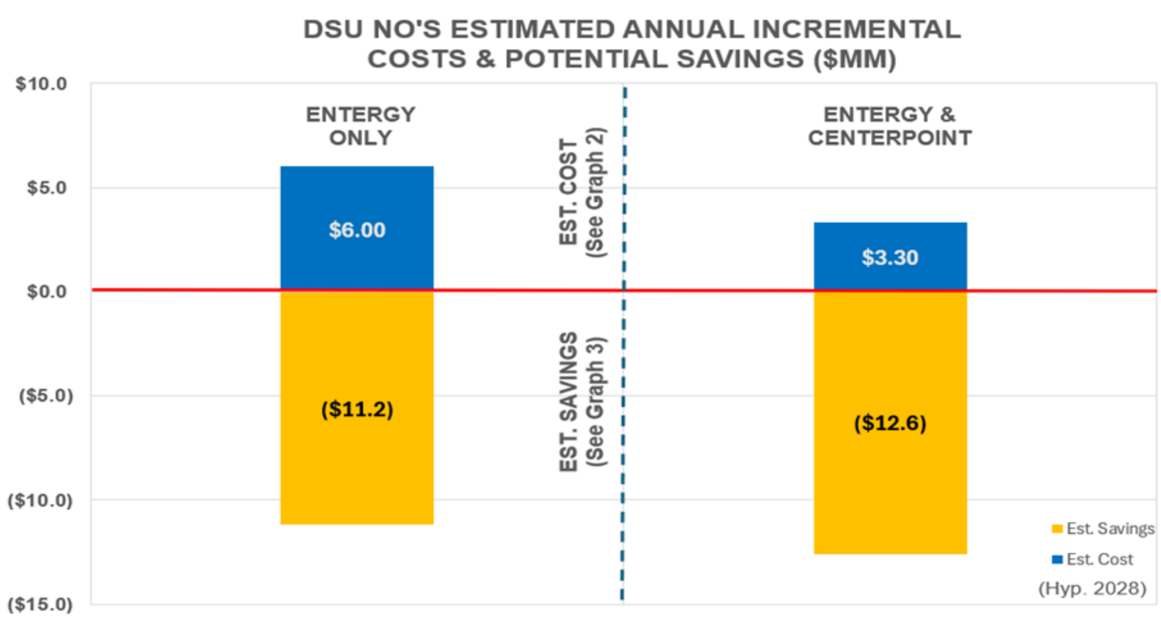
[99] Hearing Exhibit DSU NO – 6, Rebuttal Testimony (Public Redacted) of Brian K. Little, DSU NO witness, at 9:22-10:16 and Exhibit BL-7, at 4 (June 28, 2024).

[100] Hearing Exhibit DSU NO – 6, Rebuttal Testimony (Public Redacted) of Brian K. Little, DSU NO witness, at 24:9-13 (June 28, 2024); Hearing Exhibit DSU NO - 15, Rebuttal Testimony (Public Redacted) of David E. Dismukes, DSU NO witness, at 6:18-19 (June 28, 2024) (as corrected July 17, 2024). See also for $1.4 million: HSPM-CS DSU NO Response to CNO 1-8, Attachment A (Cited in Advisors Testimony) at Tab “DSU NO O&M Forecast ENO” (sum of F10:F17 X 10% = $1.4 million).

2. <u>Advisors Fail to Recognize the Transaction Results in, at a Minimum, No Net Harm with Significant Potential Upside</u>

The Advisors have elevated factor "(e)" of the Restructuring Resolution's 18-factor public interest analysis over all other factors. This factor considers whether a transaction will result in net benefits to ratepayers over the short and long term. The answer to this question relating to the Transaction is yes, <u>*if the Council considers benefits that will flow through to ratepayers beyond IT O&M efficiencies*</u>. As shown in Graph No. 1, copied below, on an annual basis the Transaction is estimated to result in greater benefits to ratepayers than cost.

<u>Graph No. 1</u>



DSU NO continues to support consideration of all public interest factors without elevating factor "(e)" above all others. However, in considering factor "(e)," DSU NO urges the Council to recognize all of the ratepayer benefits of the Transaction that have been supported in evidence by DSU NO. The outcome of this analysis *prior to considering the* *economic impact of the transaction* on New Orleans exceeds the no harm standard to support the Transaction clearly being in the public interest.

3. <u>Significant Economic Benefits of Transaction are Over and Above the Net Ratemaking Benefits</u>

The Advisors evaluate the significant economic benefits of the Transaction under factor "(j)" of the Restructuring Resolution.[107] However, despite the millions in economic benefits of the Transaction to the City of New Orleans, the Advisors qualify its conclusion that the Transaction can reasonably be assumed to be beneficial on overall basis to New Orleans' economies and communities in the area on whether the ratepayer impacts under factor "(e)" are mitigated to the Council's satisfaction.[108] The Restructuring Resolution does not elevate any one factor over another, nor does the Restructuring Resolution require factor "(e)" to be satisfied in order to recognize the significant economic benefits of the Transaction will be beneficial on overall basis to the City. It is inconsistent for the Advisors to tie these two factors together for purposes of an evaluation of factor "j" when the Advisors have made clear economic benefits and ratepayer benefits are separate and distinct considerations.[109]

The Council should recognize that the Transaction is beneficial on an overall basis to the City of New Orleans. DSU NO has demonstrated through the economic analysis performed by Dr. David Dismukes that the Transaction will result in significant economic benefits to the City.[110] The results of Dr. Dismukes analysis indicate significant economic

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[107].Advisors Original Brief at 28 and 35-36 (October 15, 2024).

[108] Advisors Original Brief at 28-29 (October 15, 2024).

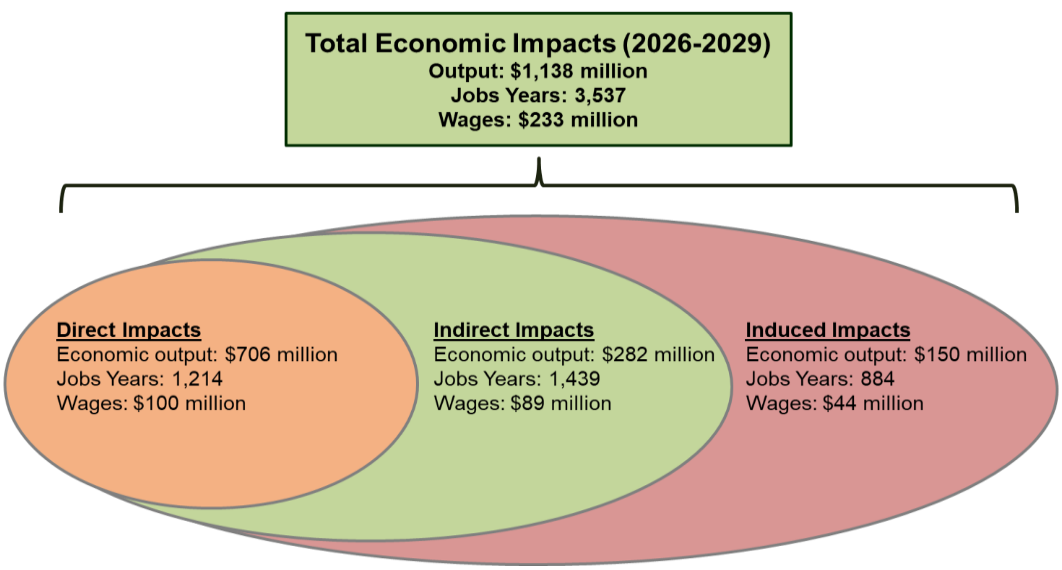
[109] Advisors Original Brief at 2 (October 15, 2024).

[110] Hearing Exhibit DSU NO – 15, Public-Redacted Rebuttal Testimony of David E. Dismukes, Ph.D., DSU NO witness, at Exhibit DED-4 (June 28, 2024) (as corrected July 17, 2024).

benefits from the Transaction, **including more than $1 billion in economic output over the first four full years of DSU NO ownership,** which does not include the additional benefits expected with the closing of both the Entergy and CenterPoint transactions.[111] Importantly, due to DSU committing to locate its corporate headquarters in the City of New Orleans, ***between 95% and 98% of all economic benefits will be realized by the City of New Orleans***.[112]

Moreover, these economic benefits are over and above the Transaction's ratepayer benefits. As shown below, the economic benefits provide millions in economic benefits, particularly to Orleans Parish, on top of the ratepayer benefits previously discussed.

Graph No. 4: Economic Benefits of Entergy-Only Transaction[113]



[111] Hearing Exhibit DSU NO – 15, Public-Redacted Rebuttal Testimony of David E. Dismukes, Ph.D., DSU NO witness, at 44, Table 1 (June 28, 2024) (as corrected July 17, 2024).

[112] Hearing Exhibit DSU NO – 18, Rejoinder Testimony of David E. Dismukes, Ph.D., DSU NO witness, at Exhibit DED-2 (September 3, 2024).

[113] Hearing Exhibit DSU NO – 15, Rebuttal Testimony (Public Redacted) of David E. Dismukes, Ph.D., DSU NO witness, at Exhibit DED-4, see slides 18-19 and 25-26 (June 28, 2024) (as corrected July 17, 2024).

It is unreasonable and punitive not to recognize these significant economic benefits of the Transaction to New Orleans, and DSU NO's satisfaction of factor "(j)," in this proceeding unless DSU NO eliminates or mitigates to the Council's satisfaction the Advisors' overstated Transaction impacts on ratepayers, which can only be addressed in a proceeding when DSU NO's rates are actually before the Council.

C. Advisors Fail to Recognize the Need for the Cloud-Based IT System and Benefits from Scalability of the System Evidenced by the CenterPoint Transaction

The Advisors continue to dispute the need for and benefits of a modern, cloud-based system, including benefits from the scalability of the system as evidenced by the CenterPoint transaction.

1. A Need for the Cloud-Based IT System Exists.

The Advisors claim that the proposed cloud-based system is not needed to serve gas customers *but for* the Transaction, as they claim there is no evidence in the record that ENO's current 2005 on-premises system is inadequate.[114] That is simply not correct. As DSU NO witness Brian Little testified, the 2005 on-premises system currently serving gas customers has numerous critical systems that are beyond technical support and more are expected to be beyond support in the near term.[115] Further, the Advisors themselves have stated ENO's IT assets only have 15-year service lives, putting the 2005 system beyond its useful life in 2020.[116]

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[114] Advisors Original Brief at 17 (October 15, 2024).

[115] Hearing Exhibit DSU NO – 6, Rebuttal Testimony (Public Redacted) of Brian K. Little, DSU NO witness, at 15:11-16:7 (June 28, 2024).

[116] Hearing Exhibit ADV – 12, Surrebuttal Testimony of Byron S. Watson (Public Redacted), Advisors witness, at 16:3-17:7 (August 5, 2024).

In addition, ENO has indicated that it intends to migrate to a cloud-based system, but just has not yet identified when.[117] This is not an issue of "if" but simply an issue of "when," and illustrates a benefit of the Transaction and the opportunity it creates for DSU NO to implement a *greenfield* cloud-based IT system.

As Dr. Dismukes testified, transitioning to a cloud-based system is consistent with the industry trend because of the benefits of such system.[118] Even the City of New Orleans has begun to migrate to cloud-based technology - - and did so without the need for a quantitative CBA as being required by the Advisors to support the reasonableness of the transition.[119] As DSU NO discussed in testimony, a utility should not wait for the technology backbone of the gas system to crash to replace it. CenterPoint was highly criticized for this following Hurricane Beryl.[120] However, the philosophy of the Advisors would result in waiting until critical gas infrastructure is broken with impacts on safety and reliability before updating.

Clearly, DSU NO has supported the need for implementation of a cloud-based IT system.

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[117] Hearing Exhibit DSU NO – 9, Rejoinder Testimony (Public Redacted) of Brian K. Little, DSU NO witness, at Exhibit BL-1 (September 3, 2024).

[118] Hearing Exhibit DSU NO – 18, Rejoinder Testimony of David E. Dismukes, Ph.D., DSU NO witness, at 32:17-33:20 (September 3, 2024).

[119] Hearing Exhibit DSU NO – 18, Rejoinder Testimony of David E. Dismukes, Ph.D., DSU NO witness, at 33:21-34:12 (September 3, 2024).

[120] Hearing Exhibit DSU NO – 18, Rejoinder Testimony of David E. Dismukes, Ph.D., DSU NO witness, at 31:9-14 (September 3, 2024)., citing: Texas Senate Special Committee on Hurricane and Tropical Storm Preparedness Recovery and Electricity – YouTube, https://www.youtube.com/watch?v=MpbM2q8YXw8, at 6:47:03.

2. <u>CenterPoint Transactions Supports Benefits to Gas Customers from Scalability of Cloud-Based IT System</u>

The CenterPoint transaction would further reduce the Advisor overstated revenue requirement of the Transaction by $2.7 million, after adjusting for errors previously discussed.[121]

The CenterPoint transaction would be known and the impact measurable at the time of a future rate case.[122] Yet, in their Original Brief, the Advisors fail to mention this important mitigation - - *a mitigation which is possible because of the <u>scalability</u> of the cloud-based IT system that will be implemented as part of the Transition Plan.*

The CenterPoint transaction is not only an important consideration in terms of the increased economies of scale it brings to reduce any impact of the Transaction on gas customers, but also is important because it allows for ongoing savings in shared services O&M expenses, increasing the ratepayer benefits of the Transaction, as show in Graph Graphs 1 and 3, previously presented.

While the specific dollar amount related to the <u>scalability</u> of the cloud-based IT system may be hard to quantify, the benefits, as demonstrated by the CenterPoint Transaction, are real and would be realized by gas customers.

[121] *See* Graph No. 2 to this Reply Brief, which presents the corrections to the Advisors cost impact analysis as performed by Dr. Dismukes in Rebuttal Testimony (Hearing Exhibit DSU NO-17 at Exhibit DED-1) but using a 6.61% cost of debt (Hearing Exhibit ADV – 12, Watson Surrebuttal Testimony at 25:5-9) and 100% sharing of goodwill amortization credit.

[122] The future rate case would not be initiated sooner than 15-months post-Closing of the Entergy Transaction or in late 2027 - - or about two years from now.

D. Question of Prudence Amounts to $1 Million Issue

In their Original Brief, the Advisors recommend the Council approve the Transaction subject to conditions that include a mitigation framework proposed by Advisors witness Mr. Joseph Rogers in Surrebuttal Testimony.[123] In proposing the framework, the Advisors have argued that approval of the mitigation framework is needed in this proceeding because the Council is limited in its ability to deny costs in a future proceeding pursuant to the Prudent Investment Rule.[124] However, the mitigation framework proposed by the Advisors goes beyond issues that would be subject to a prudence inquiry and includes issues more appropriate to be addressed in a future rate case. In fact, as discussed below, the Prudent Investment Rule would apply to what may be only a $1 million issue.

1. <u>Non-Prudence Issues Are Appropriate for Rate Case</u>

The Advisors' mitigation framework includes potential cost impacts that go beyond recovery of Transition Plan Costs that would be subject to a prudence evaluation in the future rate proceeding. These issues include ADIT impact, cost of debt impact, depreciation/amortization period for recovery of Transition Plan Costs, and the value of the Retained Asset credit.[125] However, these impacts can only be determined in a future rate proceeding when more data is available. Moreover, the Council's evaluation of these items is not tied to a prudence inquiry.

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[123] Advisors Original Brief at 21 (October 15, 2024).

[124] Advisors Original Brief at 33-34 (October 15, 2024).

[125] Hearing Exhibit ADV – 12, Surrebuttal Testimony of Byron S. Watson (Public Redacted), Advisors witness, at 55:1-56:21 (August 5, 2024).

Further, DSU NO has agreed to mitigations for the ADIT and cost of debt impacts separate and apart from any mitigation relating to its recovery of Transition Plan Costs. For example, DSU NO has proposed (i) to absorb the impact of the loss of ADIT between Closing and establishing new rates in a future rates, (ii) to use an extended amortization period for recovery of the regulatory asset, and (iii) to share with customers the goodwill tax benefits from the Transaction.[126] And, with respect to cost of debt, DSU NO has acknowledged that the Council has the authority to authorize a hypothetical cost of debt for DSU NO.[127]

With respect to the Retained Asset credit, as previously discussed, the Advisors unnecessarily reduced the Retained Asset credit to eliminate the net book value of facility assets that are not transferring to DSU NO. DSU NO has directly and factually disputed this in testimony.[128] However, like the ADIT and cost of debt impacts, the value of the Retained Assets to apply as a credit against Transition Plan Costs is not a prudence issue and should not be included in a mitigation framework. These are all issues that will be determined in the future rate proceeding but that do not fall under the Prudent Investment Rule, or the limitations of the Prudence Investment Rule the Advisors raise as a concern.

2. Prudence Inquiry is a $1 Million Prudence Issue

The only prudence issue for the Council in the future rate proceeding is DSU NO's Transition Plan Costs, which largely is the cost of the cloud-based IT system. As

[126] DSU NO Initial Brief at 70, Table 4 (October 15, 2024).

[127] Hearing Exhibit DSU NO – 4, Rebuttal Testimony (Public Redacted) of Jeffrey Yuknis, DSU NO witness, at Exhibit JY-2, Section B., No. 5 (June 28, 2024).

[128] Hearing Exhibit DSU NO – 6, Rebuttal Testimony (Public Redacted) of Brian K. Little, DSU NO witness, at 25:29-27:2 (June 28, 2024); Hearing Exhibit DSU NO – 9, Rejoinder Testimony (Public Redacted) of Brian K. Little, DSU NO witness, at 4:3-6:6 (September 3, 2024).

explained in DSU NO's testimony, DSU NO and its affiliates must replace Retained Assets to standup the natural gas local distribution company. The Retained Assets include certain assets of ENO that were used to provide service to the Gas Business but are being retained by ENO for its gas operations. Replacing these Retained Assets includes implementation of a modern, cloud-based IT system, leasing of new facilities, and standing up a new shared services system. DSU NO has proposed to defer these "Transition Plan Costs" to a regulatory asset in order to have the opportunity to seek recovery in the future rate proceeding, subject to a prudence review. These costs represent the only prudence issue for the future rate proceeding.

Importantly, at the time of the future rate proceeding, the outcome of the CenterPoint Transaction will be known and the impact on Transition Plan Costs to ENO measurable. DSU NO has presented evidence supporting that with the closing of the Entergy and CenterPoint transactions, the Transition Plan would be implemented for about $1 million more than the current net book value of the Retained Assets in ENO's rate base.[129] Thus, the prudence inquiry in the future rate proceeding would only amount to a $1 million issue.

DSU NO submits that this limited prudence issue does not require any mitigation framework to be adopted in this proceeding much less one that incorporates non-prudence issues, such as potential ADIT and cost of debt impacts.

[129] DSU NO Initial Brief at 58, Table 3 (October 15, 2024).

E. Evidence Supports Approval of Transaction Under Public Interest Standards without Advisors Punitive Recommendations

The analysis being performed by the Advisors is inaccurate, incomplete, and unnecessary, and is being performed in a way that will ensure customers and the City of New Orleans will miss out on the beneficial opportunity the Transaction presents. Advisors are focused on the past (refusing to accept forecasts and estimates – even though real data will be available at the time of the rate case), while Delta is focused on the opportunity for the future. The advisor estimate is overstated, relying partially on key variables such as ADIT, cost of debt, depreciation/amortization, and the Retained Asset credit that are more appropriate for determination in a future filing.

While the Advisors continue to relay concern regarding a future prudence review, as discussed above, the only item that would be subject to the prudence inquiry is the limited amount of Transition Plan Costs after netting against the Retained Asset credit.

Further, DSU NO has submitted a prudence framework that should have alleviated the Advisors concern regarding a future, limited prudence review by agreeing to mitigate impacts of the Transaction to the Council's satisfaction *<u>once benefits of the Transaction are properly considered</u>*. Additionally, to the extent the combined impact of all the above would result in significantly higher rates, the Council still has the authority to set just and reasonable rates for gas customers.[130]

DSU NO would expect mitigation to occur to conform impacts of the Transaction - - beyond the benefits of the Transaction - - with its duty to set just and reasonable rates.

[130] DSU NO Initial Brief at 80 (October 15, 2024), citing Docket No. UD-18-07, *Revised Application of Entergy New Orleans, LLC for a Change in Electric and Gas Rates Pursuant to Council Resolutions R-15-194 and R-17-504 and for Related Relief*, Resolution and Order at 3 (November 7, 2019).

However, mitigation should not be limited to a set formula prior to determining the actual impact (cost less benefits), if any. DSU NO is bearing the risk of these costs by closing with no adjustment in rates and is only proposing to (i) complete the project, (ii) operate the assets for a period of time to develop actual benefits and savings (at least 15 months), and (iii) have an opportunity to demonstrate the actual costs and benefits of the transaction when the data is available. DSU NO has already committed to working with the counsel to mitigate any impact from costs exceeding the benefits demonstrated in that proceeding to the Council's satisfaction.[131] Thus, there is no need to approve the Transaction subject to the Advisors proposed mitigation framework that would severely limit the ability of DSU NO to demonstrate the benefits of the Transaction. Such an overly restrictive framework is inconsistent with past practice of the Advisors and Council and would only serve to punish DSU NO for bringing this rate and beneficial opportunity to the City of New Orleans and gas customers.

1. <u>Advisors Extreme Positions Make Showing Transaction Benefits in Future Rate Case Difficult</u>

In their Original Brief, the Advisors state that DSU NO has not supported the benefits of the Transaction.[132] However, the Advisors refuse to accept estimates or forecasts of benefits,[133] even though prepared by the same experienced third parties that prepared the Transition Plan Cost estimate used by the Advisors in their impact analysis.

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[131] Hearing Exhibit DSU NO-18, Rejoinder Testimony of David E. Dismukes, Ph.D., DSU NO witness, at Exhibit DED-3 (September 3, 2024) Initial Brief at 59 (October 15, 2024).

[132] Advisors Original Brief at 18 (October 15, 2024).

[133] Advisors Original Brief at 18, 23, 37 (October 15, 2024).

How can DSU NO be expected to support a future transformational project, that will provide benefits over years to come, without using forecast and forward-looking data?

Notably, even factor "(e)" of the Restructuring Resolution explicitly references short-term *and long-term* benefits and *forecasted* benefits.

While on one hand, the Advisors find it acceptable to present to the public and Council an estimated revenue requirement and residential bill impact using assumptions for input not yet able to be known, on the other hand the Advisors refuse to recognize benefits to ratepayers that DSU NO has quantified and presented in evidence in this proceeding.[134] As discussed herein, the Advisors' impact analysis is one-sided and completely fails to acknowledge or accept benefits to customers that have been provided throughout the record.

2. Advisors Restrictions on Transaction Benefits Prejudices DSU NO

As the Advisors state in their Original Brief, the Advisors recommend limiting the short-term and long-term benefits of the Transaction only to those quantifiable benefits that flow through to a ratepayer's bill.[135] And, the Advisors seek to implement a mitigation framework that would only recognize one category of quantifiable benefits - - O&M savings due solely to efficiencies from a cloud-based IT system compared to ENO's costs in the final gas formula rate plan ("GFRP") evaluation as adjusted for inflation.[136]

[134] For example: Hearing Exhibit DSU NO – 15, Rebuttal Testimony (Public Redacted) of David E. Dismukes, Ph.D., DSU NO witness, at Exhibit DED-5 (June 28, 2024) (as corrected July 17, 2024); Hearing Exhibit DSU NO – 17, Rebuttal Testimony (HSPM-CS) of David E. Dismukes, Ph.D., DSU NO witness, at HSPM-CS Exhibit DED-6 (June 28, 2024) (as corrected July 17, 2024); Hearing Exhibit DSU NO – 6, Rebuttal Testimony (Public Redacted) of Brian K. Little, DSU NO witness, at Exhibit BL-11, page 7 (June 28, 2024).

[135] Advisors Original Brief at 24 (October 15, 2024).

[136] Advisors Original Brief at 37 (October 15, 2024).

Moreover, the Advisors want the Council to put these limitations in place *now* through a "mitigation framework" - - *two years prior* to DSU NO requesting to recover Transition Plan Costs and needing to demonstrate benefits of the costs.[137]

The Advisors recommendation to limit ratepayer benefits that the Council can consider under factor "e" of the Restructuring Resolution in their proposed mitigation framework is unreasonable and would only serve to prejudice DSU NO's ability to recover prudently incurred costs. It is simply impossible to demonstrate benefits if rate-related benefit estimates of a future project, which is "evergreen" in nature, cannot be provided.

a. It is reasonable and consistent with Council precedent to include both qualitative and quantitative Transaction benefits.

There is no reason that DSU NO should not be allowed to include quantifiable and qualitative benefits to support the recovery of costs associated with the Transition Plan. The Advisors themselves have agreed to inclusion of such costs in other utility proceedings, including specifically ENO's application to implement and recover the costs associated with a $75 million AMI system and ENO's request to join the Midcontinent System Operator ("MISO") Regional Transition Organization ("RTO") and to remain in the MISO RTO.

In Docket UD-16-04, the Advisors agreed that the AMI project was prudent and in the public interest based on many qualitative customer benefits. The Term Sheet, which was attached to and incorporated in the Council Resolution provided in part:[138]

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[137] Advisors Original Brief at 37 (October 15, 2024).

[138] Docket No. UD-16-04, *Application of Entergy New Orleans, Inc. for Approval to Deploy Advanced Metering Infrastructure, And Request for Cost Recovery and Related Relief*, Resolution and Order No. R-18-37 at page 2-3 of the incorporated Stipulated Settlement Term Sheet (February 8, 2018) ("AMI Resolution") (emphasis added).

3. ENO and the Advisors, through this Stipulation, agree that the proposed AMI Implementation, as detailed in ENO's Application, including the removal and retirement of existing metering equipment, and the installation of new advanced meters and supporting systems and equipment, and a customer education plan, as modified herein is in the public interest, serves the public convenience and necessity, and therefore is prudent.

4. The prudence determination in paragraph 3 recognizes that, while ENO and the Advisors differ as to the magnitude and methodology for calculating net benefits, both agree that the Company's proposed AMI Implementation is reasonably expected to produce, in the long-term, benefits in excess of the costs of AMI .on a combined electric and gas basis.

5. The prudence determination in paragraph 3 also recognizes that, while ENO and the Advisors differ as to several aspects of regulatory policy and principles, both agree that the Company's proposed AMI Implementation is beneficial for customers and should therefore be approved as modified herein.

….

7. The Company's proposed AMI Implementation *provides the technology platform to achieve <u>greater grid resiliency</u> in the distribution network, <u>improved outage and reliability</u>, <u>performance</u>, <u>improved grid planning</u> for modifications and improvements, <u>DSM programs</u>, <u>time differentiated pricing</u>, and <u>specially designed customer options</u>, among other system and customer benefits*.

In addition, in the Council's Resolution and Order approving ENO's continued participation in the Midcontinent Independent System Operator ("MISO") Regional Transmission Organization ("RTO"), the Council likewise cited to qualitative benefits and qualitative risks support approval of the application - - with which the MISO Resolution explicitly indicates the Advisors agreed:[139]

[139] Docket NO. UD-17-02, *Application of Entergy New Orleans, Inc. for Approval Regarding Continued Participation In The Midcontinent Independent System Operator, Inc. Regional Transmission Organization,*

> **WHEREAS,** ENO's Application also listed several qualitative benefits from MISO participation, *e.g.,* increased price transparency, increased transmission planning processes and coordination, seams management, market oversight, congestion management, access to ancillary service providers; and
>
> **WHEREAS,** ENO also argued there are qualitative risks from exiting MISO and continued MISO participation; and
>
> **….**
>
> **WHEREAS,** the *Advisors acknowledged* that ENO's *membership in MISO has provided qualitative benefits*, including, among other things, greater transparency on market operations and transmission system conditions, regional transmission planning, and access to lower cost generation. The Advisors stated *they expect these qualitative benefits to continue* with ENO's continued membership in MISO; and
>
> **WHEREAS,** the *Advisors agreed* that, *based on the Application, the quantitative and qualitative cost-benefit analyses*, and ENO's discovery responses, ENO's membership in *MISO remains in the public interest*; and

Thus, the Advisors' recommended structure for its mitigation framework in this proceeding is inconsistent with its and the Council's prior recognition in the AMI Resolution and Order and MISO Resolution and Order of the value of both qualitative and quantitative benefits in a transformational IT project.

Importantly, the qualitative benefits cited above from the AMI Resolution and Order are representative of several of the qualitative benefits of the Transition Plan, as identified by DSU NO,[140] and particularly the transformational cloud-based IT system, that the

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Resolution and Order No. R-17-627 at 3 and 9 (December 14, 2017) ("MISO Resolution") (emphasis added).

[140] Hearing Exhibit DSU NO – 9, Rejoinder Testimony (Public Redacted) of Brian K. Little, DSU NO witness, at 10:3-13:10 (September 3, 2024).

Advisors are refusing to recognize in this proceeding. As DSU NO witness Mr. Brian Little testified, and as DSU NO discussed in its Initial Brief, there are numerous qualitative benefits to ratepayers from a core-focused IT system that may not flow through to a customer's bill:[141]

> 5. Lastly and in addition to scalability, DSU NO's investment in a core-focused, modern cloud-based IT system provides several benefits some of which may not necessarily directly result in reduced O&M, particularly IT O&M.[142] These benefits are discussed in my Rebuttal Testimony (pages 8 to 15) and the Accenture Memo included as Exhibit BL-7 to Rebuttal Testimony, summarized in Exhibit DED-1 to Dr. Dismukes Rejoinder Testimony and incorporated into the Transition Cost Prudence Evaluation Framework provided in Exhibit DED-3 to Dr. Dismuke's Rejoinder Testimony.[143] These benefits encompass the categories of, among others:
>
> a. **Adaptability** of off the shelf configurable software;
>
> b. **Faster, more frequent and lower cost upgrades**;
>
> c. **Resiliency** significantly reducing the risk of "single points of failure" due to operational disruptions caused by such events as hurricanes and named storms through built-in redundancies and back-ups;
>
> d. **Gas-centric and core-focused customer interactions** driving customer service and satisfaction;
>
> e. **Cyber and physical security** risks significantly reduced through the high level of standardization and built-in redundancies;
>
> f. **Energy efficiency** reducing energy consumption by 22% to 93% as compared to on-premises IT system platforms:
>
> g. **Consolidation** of IT systems and vendors within the IT ecosystem; and
>
> h. **Integration** through the cross-ecosystem use of data enabling "single truth of master data," reducing duplicity in data entry and eliminating unnecessary reconciliations and complex integrations.

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[141] DSU NO Initial Brief at 85 (October 15, 2024).

[142] Hearing Exhibit DSU NO – 9, Rejoinder Testimony (Public Redacted) of Brian K. Little, DSU NO witness, at 12:9-11 (September 3, 2024).

[143] Hearing Exhibit DSU NO – 6, Rebuttal Testimony (Public Redacted) of Brian K. Little, DSU NO witness, at 8:17-15:3, page 7 (June 28, 2024).

The above benefits of the cloud-based IT system are akin to the AMI benefits relied upon by the Council in approving ENO's $75 million AMI project. Thus, it is inconsistent of the Advisors to argue that benefits of the Transition Plan only have value if can be quantified and flow through a customer's bill. As DSU NO witness Mr. Brian Little testified, a limited framework for evaluating the benefits of technology and platform transformations, such as included in the proposed Transition Plan, does not permit an appropriate review to be conducted by the Council;[144] a limited breadth and scope of analysis will not capture the numerous benefits of core-focused, modern cloud-based IT platforms,[145] nor will it allow the Council to perform a holistic review and analysis of the significant benefits achieved by DSU NO outside of the IT platform, as detailed throughout this proceeding, and summarized in Exhibit DED-1 to Dr. Dismuke's Rejoinder Testimony (and provided as Exhibit D to DSU NO's Initial Brief).

b. It is reasonable and consistent with Council precedent to use forecasted benefits and studies.

The Advisors' recommendation for DSU NO to only be able to support Transition Plan Costs with actual savings that flow through to a customer's bill not only eliminates valuable qualitative benefits, as discussed above, but also would eliminate the opportunity for DSU NO to use studies and forecasted benefits to support the benefits of an evergreen IT system and other elements of the Transition Plan expected to result in efficiencies and savings. However, this position of the Advisors is also inconsistent with their and the Council's prior acceptance of studies and forecasts to support the public interest.

[144] Hearing Exhibit DSU NO – 9, Rejoinder Testimony (Public Redacted) of Brian K. Little, DSU NO witness, at 9:8-10 (September 3, 2024).

[145] Hearing Exhibit DSU NO – 9, Rejoinder Testimony (Public Redacted) of Brian K. Little, DSU NO witness, at 8:3-9:8 (September 3, 2024).

For example, in ENO's applications to join and to remain in MISO, the Council relied on forecasted benefits of ENO's joining and remaining in MISO. In Council Resolution and Order No. R-17-627, the Council recited the ***forecasted*** benefits provided by ENO in support of the Council's determination that it was in the public interest for ENO to join MISO:[146]

> **WHEREAS**, the Joint MISO Application requested that the Council find that the transfer of functional control of ENO's and ELL's electric transmission assets to MISO to facilitate ENO's and ELL's membership therein is in the public interest; and
>
> **WHEREAS**, the Joint MISO Application *estimated* that, with Entergy and CLECO Power, LLC joining the MISO RTO, ENO would have an approximate total of *$32 million to $46 million in net benefits, in terms of net present value, over a ten-year period*; and
>
> **WHEREAS**, the Joint MISO Application *estimated* that ELL-Algiers' portion *of ELL's estimated net benefits would be approximately $7 million to $9 million over* the same time frame; and
>
> **WHEREAS**, on November 15, 2012, the Council, in Docket No. UD-11-01, adopted Council Resolution No. R-12-439 that approved the Stipulation and Settlement Agreement ("Settlement Agreement") entered between ENO, ELL, the Council Advisors, and MISO agreeing to the transfer of functional control of ENO's and ELL's transmission assets to MISO. In doing so, *the Council found that ENO and ELL joining MISO was in the public interest*, subject to certain conditions and contingencies; and

Similarly, in Council Resolution and Order No. R-17-627, the Council found that it was in the public interest for ENO to continue to participate in MISO, relying on ***forecasted*** energy and capacity benefits provided by ENO, among other data. In fact, the Resolution memorializes that the Advisors agreed with use of these forecasted benefits in support of the Council's decision:[147]

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[146] MISO Resolution at 3 (December 14, 2017) (emphasis added).

[147] MISO Resolution at pages 5-10 (December 14, 2017) (emphasis added).

WHEREAS, *ENO's Application included a forward-looking analysis on capacity-related benefits* that looked at the cost difference in the reserve requirement between ENO staying in MISO and ENO exiting MISO and forming a stand-alone Balancing Authority. ENO argued that staying in MISO will result in $317 million, on a present value basis (in 2016 dollars), in net benefits from 2019-2028, or at least $32 million per year (in 2016 dollars), on average, over this period. This included $261 million in capacity-related savings and $56 million in avoided exit costs and obligations from leaving MISO, which included ENO's exit obligations under MISO's tariff and Transmission Owners Agreement and ENO's internal costs of transitioning to a standalone Balancing Authority; and

WHEREAS, ENO noted that it had not completed its forward-looking analysis on energy-related benefits *(i.e.,* AURORA results) and would supplement its Application when those results were available; and

....

WHEREAS, ENO's Supplemental Testimony contained the *forward-looking analysis of the energy-related benefits* using the AURORA production cost modeling and simulations to compare the estimated variable supply cost effects of ENO staying in MISO and ENO exiting MISO and operating as a stand-alone Balancing Authority. ENO argued that the results of this analysis showed that staying in MISO resulted in $209 million (in 2016 dollars) in energy-related net-benefits from 2019-2028; and

WHEREAS, *ENO argued that the total net-benefits of the forward-looking analysis, inclusive of the forward-looking energy-related benefits, now resulted in a net-benefit of $526 million*, on a present value basis (in 2016 dollars), or $53 million per year (in 2016 dollars), on average, over the 2019-2028 period; and

....

WHEREAS, the *Advisors evaluated ENO's forward-looking cost-benefit analyses* and, similar to ENO's historical cost-benefit analysis, *determined that the benefits derived by ENO may be overstated* due to the relatively high planning reserve margin assumption used in ENO's forward-looking capacity-related analysis for ENO exiting MISO and operating as a stand-alone Balancing Authority. *Yet, the Advisors* found that if the planning reserve margin used in ENO's analysis were more in line with traditional utility planning, *ENO's forward-looking capacity benefits for staying in MISO (although smaller) would still be expected to be positive*; and

....

> **WHEREAS,** the *__Advisors agreed__* that, based on the Application, the *__quantitative and qualitative cost-benefit analyses__*, and. ENO's discovery responses, ENO's *__membership in MISO remains in the public interest__*; and
>
> **WHEREAS,** the Advisors recommended that the Council find that ENO's request for continued participation in MISO remains in the public interest, subject to the recommended conditions and reporting requirements; and

Thus, again, it is inconsistent for the Advisors to rule out DSU NO's use of any studies or forecasted savings in the future rate case filing that will not be made until two years from now.

Moreover, as Dr. Dismukes has testified, it is typical and reasonable to rely on studies and forecasted benefits to support a transformation IT project, such as DSU NO's implementation of a cloud-based IT system because of the difficulty in quantifying benefits associated with such projects:[148]

> Similar IT transformation projects are occurring across the country, and studies, estimates and analysis are necessarily required to support implementation of the projects - - otherwise, no utility would have available data to support regulatory approval and cost recovery of such projects.

Moreover, many benefits will accrue over time, and thus, it is reasonable to estimate such benefits until such time as can be measured.[149]

Thus, to the extent a mitigation framework is adopted in this proceeding, DSU NO urges the Council to recognize that consideration of forecasted benefits and use of

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[148] Hearing Exhibit DSU NO – 18, Rejoinder Testimony of David E. Dismukes, Ph.D., DSU NO witness, at 6:25 – 7:3 (September 3, 2024)

[149] Hearing Exhibit DSU NO – 18, Rejoinder Testimony of David E. Dismukes, Ph.D., DSU NO witness, at 28:14 – 35:6 (September 3, 2024).

studies, non-DSU NO specific analyses and estimates are appropriate for evaluating the benefits of the transformative project before it.[150]

II. RESPONSE TO AAE'S EXTREME AND HARMFUL PROPOSALS

In its Original Brief, the AAE continues its baseless claims the Transaction does not pass the Council's 18 public interest factors that must be met for approval of mergers or asset transfers defined in Resolution R-06-88.[151] Consistent with its testimony in this proceeding, the central theme of the AAE's arguments against the Transaction surrounds its incorrect assertions that the Council's 18 factors somehow requires requests of this nature to include a proposal to address climate change in addition to having specific greenhouse gas ("GHG") emissions reduction targets.[152] Furthermore, the AAE wrongly associates changes in operation of the S&WB to the Transaction[153] – despite the operations of the S&WB being completely independent of whether the Gas Business is owned by ENO or sold to DSU NO.[154]

DSU NO, ENO and the Advisors have all agreed that the climate change and the elimination of GHG emissions have no direct relevance on whether this Transaction is in the public interest and that the AAE's proposals go far outside the scope of this proceeding.[155] Moreover, as Dr. Dismukes has testified, the AAE's proposals have wide

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[150] Hearing Exhibit DSU NO – 18, Rejoinder Testimony of David E. Dismukes, Ph.D., DSU NO witness, at 7:6-9 (September 3, 2024).

[151] AAE Initial Brief at 3-4 (October 15, 2024).

[152] AAE Initial Brief at 3-6 (October 15, 2024).

[153] AAE Initial Brief at 3 and 6 (October 15, 2024).

[154] Hearing Exhibit DSU NO – 15, Rebuttal Testimony (Public Redacted) of David E. Dismukes, Ph.D., DSU NO witness, at 56:16-19 (June 28, 2024) (as corrected July 17, 2024).

[155] Hearing Exhibit DSU NO – 15, Rebuttal Testimony (Public Redacted) of David E. Dismukes, Ph.D., DSU NO witness, at 56:18-20 (June 28, 2024) (as corrected July 17, 2024); Advisors Original Brief at 38-39 (October 15, 2024).

ranging economic, social, and political ramifications for a large number of other stakeholders in New Orleans and Louisiana that the AAE failed to even consider.

The evidence in this proceeding supports that under the AAE proposals, at minimum, current New Orleans natural gas customers would face a relatively rapid set of electrification costs that would include (i) the costs of converting appliance uses from natural gas to electricity; (ii) increased electricity costs relative to natural gas for comparable energy end uses (i.e., space and water heating); (iii) electricity distribution rate increases that will inevitably arise in order to modernize and upgrade the electricity grid to handle the new levels and types of electricity end-uses; and (iv) potential stranded natural gas distribution costs.[156] Dr. Dismukes estimated that the total cost to retrofit residential customer homes alone could range from $1.7 billion to $3.17 billion.[157] Further, Dr. Dismukes estimated that converting customers from gas to electric, as proposed by AAE, could cause total annual energy costs to rise by $118.1 million for all current ENO residential natural gas ratepayers and $144.5 million for all commercial natural gas customers.[158] These negative impacts could ripple throughout the New Orleans economy leading to:[159]

- A reduction of annual economic output by as much as $545.4 million.

[156] Hearing Exhibit DSU NO – 15, Rebuttal Testimony (Public Redacted) of David E. Dismukes, Ph.D., DSU NO witness, at 60:7-13 (June 28, 2024) (as corrected July 17, 2024).
[157] Hearing Exhibit DSU NO – 15, Rebuttal Testimony (Public Redacted) of David E. Dismukes, Ph.D., DSU NO witness, at 60:16-19 (June 28, 2024) (as corrected July 17, 2024).
[158] Hearing Exhibit DSU NO – 15, Rebuttal Testimony (Public Redacted) of David E. Dismukes, Ph.D., DSU NO witness, at 62:19-21 (June 28, 2024) (as corrected July 17, 2024).
[159] Hearing Exhibit DSU NO – 15, Rebuttal Testimony (Public Redacted) of David E. Dismukes, Ph.D., DSU NO witness, at 62:21 – 63:4 (June 28, 2024) (as corrected July 17, 2024).

- A reduction of annual gross state product (GSP or "value added") by as much as $326.9 million.
- A reduction in annual employment opportunities by as much as 9,528 job-years.

Yet, the AAE did zero analysis on the impact of a natural gas ban on the City of New Orleans and its residents, particularly low-income residents, prior to filing testimony proposing the ban in this proceeding.[160] Consequently, the proposal is simply unfounded and irresponsible. As Dr. Dismukes testified:[161]

> **Q. IS THE ALLIANCE'S PROPOSAL TO BAN NATURAL GAS IN NEW ORLEANS WELL-FOUNDED?**
>
> A. No. The proposal, on its face, is not well-founded since it is not supported with any empirical analysis regarding impacts. The proposal does not include a CBA nor any type of rate impact analysis, nor proposal to mitigate what are likely significant rate impacts from the stranded costs likely to arise from such a rapid removal of a key industry in the New Orleans economy (i.e., removing "the" natural gas utility). The Alliance's recommendation also fails to estimate any electric industry costs and benefits that may arise from the transition of current natural gas loads to electricity, nor does the proposal provide a detail plan defining the role that ENO would have to play in this rapid electrification process. Equally important is that the Alliance's recommendation fails to consider the significant economic development impacts this would have for not only New Orleans, but Louisiana, overall. There are considerable studies that have shown electrification increases end-user energy costs, particularly for retail and commercial customers. Fuel switching also has important implications for housing, particularly multi-family housing. These electrification proposals could unintentionally reduce housing availability and/or drive-up rents to levels that are already exceptionally high. Lastly, the Alliance has not considered the economically regressive nature of such decapitalization proposals.

[160] Hearing Exhibit DSU NO – 15, Rebuttal Testimony (Public Redacted) of David E. Dismukes, Ph.D., DSU NO witness, at 63:5-20 and 59:11-60:4 (June 28, 2024) (as corrected July 17, 2024).

[161] Hearing Exhibit DSU NO – 15, Rebuttal Testimony (Public Redacted) of David E. Dismukes, Ph.D., DSU NO witness, at 59:9-60:4 (June 28, 2024) (as corrected July 17, 2024).

Thus, not only are the AAE's extreme recommendations outside the scope of this proceeding, they are harmful to New Orleans. The AAE's recommendations should be rejected by the Council and not considered in any way in evaluating whether the Transaction is in the public interest.

III. CONCLUSION

The Transaction should be embraced by the Council as a positive - - a positive for gas customers, a positive for the City of New Orleans and its surrounding communities, a positive for the State of Louisiana, and a positive for ENO gas employees and retirees. In other words, the transaction is an opportunity that is in the best interest of the public.

While opportunities come with some costs and risks, DSU NO has demonstrated that the Transaction will provide benefits exceeding costs to gas customers and has agreed to a significant number of commitments to mitigate risks of the Transaction. As a result, the Transaction and commitments made by DSU NO will collectively lead to rates that are fair, just, and reasonable and significant economic benefits that will largely benefit the City of New Orleans and its residents. These benefits collectively support a finding that the Proposed Transaction is in the public interest.

DSU NO respectfully urges the Council to approval the Transaction and the relief requested by DSU NO and ENO in the Joint Application, as in the public interest.

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CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing has been served upon the Official Service List via electronic mail.

New Orleans, Louisiana this 1st day November, 2024.

C. R. T.

Carrie R. Tournillon

Summary of DSU NO Response to Advisors' Statements in Original Brief

Advisors Statement in Original Brief	***INCORRECT & CONFUSING***
",,, the Advisors have estimated that as proposed, the Gas Transaction itself (independent of other factors) will increase revenue requirement for gas operations by $16.5 million per year, which translates into a typical residential bill impact of $12.33 per month…" *Original Brief at 2*	***Confusing*** **because rate impact is presented as a typical bill but is double the average usage of a residential customer and bears no relevance to what an average customer would expect to see on their monthly bill;** ***Incorrect*** **as it does not realistically represent a hypothetical incremental revenue requirement or residential customer bill impact.** The Advisors indicate that their estimated bill impact is for a "typical" residential customer, but "typical residential monthly bill" is actually just a term of art and not intended to mean a typical (average) bill of a residential customer; this is because as used by the Advisors, the "typical residential monthly bill" is calculated using 50 ccf,[1] which is nearly double the actual average customer usage of 27 ccf per month.[2] As demonstrated by DSU NO through historical actual data, the Advisors' "typical" residential customer is not representative of a residential customer's typical (*i.e.*, average) usage but is based on past-practice of the Council that grossly overstates the average usage of a residential customer.[3] Thus, the practice of using 50 ccf (i) is confusing in terms of demonstrating an estimated impact on an average residential customer bill, (ii) results in a customer impact that is not an accurate estimate of the impact of the Transaction on residential gas customers, and (iii) is inconsistent with the Council's review of electric costs, which are more consistent with average usage.[4] Further, regarding both the residential customer impact and total revenue requirement impact analysis, the Advisors acknowledge they have not updated their analysis since filing direct testimony,[5] which means that they have not updated their impact analysis to incorporate any of DSU NO rebuttal and rejoinder testimony that explains the errors in Advisors analysis which overstates their

[1] Advisors Original Brief at 12, footnote 48 (October 15, 2024).

[2] Hearing Exhibit DSU NO – 15, Rebuttal Testimony (Public Redacted) of David E. Dismukes, Ph.D., DSU NO witness, at 33:1-2 (June 28, 2024) (as corrected July 17, 2024).

[3] ENO 2022 Volumes and Customers, EIA Form 176.

[4] Hearing Exhibit DSU NO – 18, Rejoinder Testimony of David E. Dismukes, Ph.D., DSU NO witness, at 39:3-40:15 (September 3, 2024).

[5] Advisors Original Brief at 16 (October 15, 2024).

	impact estimate making it incorrect, confusing and unreasonable to continue to use.
"Mr. Watson's calculation of a $16.5 million increase to the gas revenue requirement and a corresponding typical residential gas bill impact of $12.33 as a result of the Gas Transaction is reliable because it is based on the most current data available, and is based on the same ratemaking calculations that the Council has customarily employed." *Original Brief at 15-16*	***Incorrect*** **as DSU NO has used actual recent data that is more reliable than a practice used for typical formula rate plan proceedings, which this is not;** ***Confusing*** **because the "ratemaking calculations" in no way represent costs responsibility of an average residential gas customer with respect to impacts of the Transaction.** First, as discussed above, "typical residential monthly bill" is a term of art and not intended to mean a typical (average) bill of a residential customer; this is because as used by the Advisors, the "typical residential monthly bill" is actually double the actual average use of a residential customer.[6] Second, neither the 50 ccf customer usage nor the 64% allocation of the $16.5 million revenue requirement to the residential customer class is based on "the most current data available" and results in residential customers paying two times the cost for the volume they use: (i) Actual historical volume data supports a much smaller (about 35%) allocation of costs to residential customers consistent with the residential class's portion of total ENO gas sales, and (ii) recent historical data supports use of 27 ccf as the average residential customer's monthly usage.[7] ***DSU has used the most current actual data available in its hypothetical incremental revenue requirement analysis, not the Advisors.*** Third, while the Advisors claim that their impact assessment is based on ratemaking calculations that the Council has customarily employed, this is not a customary formula rate plan proceeding before the Council.[8] If the Council is going to consider in this proceeding hypothetical impacts on customers two years from now (2027-2028), ***the monthly impacts should not be based on a past practice that bears no relevance to what a customer would actually expect to see on an average bill, but instead should reflect the average bill of the customer over the course of a year for customer transparency. Otherwise,***

[6] Hearing Exhibit DSU NO – 15, Rebuttal Testimony (Public Redacted) of David E. Dismukes, Ph.D., DSU NO witness, at 32:21-33:1 (June 28, 2024) (as corrected July 17, 2024).

[7] ENO 2022 Volumes and Customers, EIA Form 176.

[8] Advisors Original Brief at 3 (October 15, 2024).

	the claimed bill impact does not reflect reality and just incites concern.[9] Fourth, the Advisors' analysis indicates a $16.5 million incremental revenue requirement increase from the Transaction when claiming ratepayer "harm" but then does not consider any estimated benefits from the Transaction. This one-sided approach is prejudicial to the Transaction - - if DSU NO consultants' estimated costs are acceptable to include in an impact analysis so should those consultants' estimated benefits be included to determine a net impact, not just a cost impact. Fifth, the Advisors acknowledge late in the brief that their estimate and DSU NO's estimates are just that, estimates, and actual impacts can't be known until the rate case.[10] Thus, claiming to know an impact and put forth a specific dollar impact is confusing. Sixth, the $16.5 million figure fails to (i) properly reflect the new ADIT that will be created by DSU NO, (ii) reflect the market cost of debt is higher today than ENO's historical average, which will increase ENO's cost of debt going forward same as DSU NO, and (iii) reflect that customers may ultimately benefit from lower cost of debt over the long run from DSU NO's higher credit rating, among other issues.[11] Thus, the Advisors' incremental revenue requirement is not reflective of the entire evidentiary record and overstated.
"…the potential mitigation identified by DSU NO and ENO is insufficient to substantially mitigate the electric and gas rate impacts the Advisors have identified…" *Original Brief at 2*	***Incorrect*** **because there are no rate impacts in the Council's approving the transaction; Confusing as any future rate impacts will be subject to the Council's review of cost for prudence and authorization of just and reasonable rates.** Neither DSU NO nor ENO have requested to change gas or electric rates as part of approval of the Transaction.[12] Further, the Advisors have failed to accurately identify potential future rate impacts (discussed above) and have acknowledged a significant portion of the variables comprising the impact are not accurately determinable until the future rate case. Thus, it is not possible to analyze

[9] Hearing Exhibit DSU NO – 18, Rejoinder Testimony of David E. Dismukes, Ph.D., DSU NO witness, at 39:10-40:15 (September 3, 2024).

[10] Advisors Original Brief at 37 (October 15, 2024).

[11] Advisors Original Brief at 12, citing Ex. ADV-9 (Watson Direct) at 46 (October 15, 2024).

[12] Delta States Utilities No, LLC And Entergy New Orleans, LLC, *ex parte. In Re: Application For Authority to Operate as Local Distribution Company and Incur Indebtedness and Joint Application For Approval Of Transfer And Acquisition Of Local Distribution Company Assets And Related Relief,* Docket No. UD-24-01 (December 11, 2023) ("Joint Application"). See Joint Application at pages 29-32 (December 11, 2024).

	the sufficiency of mitigation proposed by DSU NO and ENO until an actual impact is known in an actual ratemaking proceeding.
"There is no evidence in the record that ENO's present IT system is inadequate. Any incremental benefits compared to ENO's IT system are aspiration and unproven (*e.g.*, O&M savings), and they are difficult to tie to benefits that ratepayers will notice or value." *Original Brief at 17.*	***Inaccurate*** **because evidence in the record supports ENO' system being inadequate in the near future and because DSU NO has supported benefits of a cloud-based IT System;** ***Confusing*** **because it is negatively presumptuous that customers will not notice the benefits of a cloud-based IT system.** ***Evidence in the record supports ENO's system as being inadequate in the near future:*** (1) ENO has indicated that it will move to a cloud-based system, it is just a matter of time;[13] (2) ENO's 2005 on-premises system is beyond the 15 year service life, per the Advisors' own useful life standard;[14] and (3) ENO's 2005 on-premises IT system uses critical systems that are currently beyond support and with more to lose support in the near term.[15] Moreover, New Orleans itself has started the process of migrating to a cloud-based IT system.[16] Thus, there is ample evidence in the record supporting the need for implementation of a modern, cloud-based IT system. ***Further, it is inaccurate to claim that DSU NO has not proven benefits of the cloud-based IT system.*** DSU NO has provided in the evidentiary record estimated benefits of the cloud-based IT system prepared by third-party experts and in accordance with industry standards, such as (i) the IT O&M efficiencies included in Dr. Dismuke's CBA,[17] or (ii) Total Cost of Ownership efficiencies estimated by DSU NO's IT Integration Partner, Accenture.[18] However, the Advisors have not incorporated either benefit calculations in their impact analysis. Moreover, if the Advisors insist on including only quantifiable savings (which DSU NO disputes is reasonable or consistent with precedent), the

[13] Hearing Exhibit DSU NO – 9, Rejoinder Testimony (Public Redacted) of Brian K. Little, DSU NO witness, at Exhibit BL-1 (September 3, 2024).

[14] Hearing Exhibit ADV – 12, Surrebuttal Testimony of Byron S. Watson, Advisors witness, at 17:8-19 (August 5, 2024).

[15] Hearing Exhibit DSU NO – 6, Rebuttal Testimony (Public Redacted) of Brian K. Little, DSU NO witness, at 15:6-16:7 (June 28, 2024).

[16] Hearing Exhibit DSU NO – 18, Rejoinder Testimony of David E. Dismukes, Ph.D., DSU NO witness, at 33:21-34:12

[17] Hearing Exhibit DSU NO – 17, Rebuttal Testimony (HSPM-CS) of David E. Dismukes, Ph.D., DSU NO witness, at 52:10-14 and HSPM-CS Exhibit DED-5 (June 28, 2024) (as corrected July 17, 2024).

[18] Hearing Exhibit DSU NO – 6, Rebuttal Testimony (Public Redacted) of Brian K. Little, DSU NO witness, at Exhibit BL-11, page 2 (June 28, 2024).

	project must first be completed before benefits can be *proven*, supporting DSU NO's position that costs and benefits of the system and other Transition Plan Costs should be evaluated in the initial rate case. ***Finally, it is negatively presumptuous of the Advisors to state that the benefits of a cloud-based system will not be noticed by ratepayers*** - - and in fact, the records supports the opposite, including discussion of CenterPoint customers experience following Hurricane Beryl due to its lack of use of a cloud-based IT system.[19] Moreover, the Sewerage & Water Board of New Orleans ("SWBNO"), a large gas customer of ENO, indicated its support of moving to a cloud-based IT system in its initial brief in this proceeding:[20] "SWBNO also tends to agree with Delta States that the Advisors seem to be prejudging the prudence of the Transition Plan and that the Council should not consider the cost of such IT as 'ratepayer harm.' ***All IT systems need to be replaced and/or upgraded from time-to-time. ENO's system is a 205 vintage platform and is outdated***."
	INCORRECT
"Mr. Watson's examination of this ENO data [ENO net-credit ADIT balance] found that of this balance, $58.1 million would not transfer to DSU NO's rate base at the close of the Gas Transaction. This would result in a $58.1 million rate base increase (i.e., debit) that could be partly offset by a DSU NO proposal to allow an ADIT credit related to the goodwill DSU NO will record related to the Gas Transaction." *Original Brief at 10-11*	***Incorrect*** **because the Advisors do not properly reflect in its cost analysis the amount of new ADIT to be created by DSU NO prior to any change in rates.** The Advisors fail to properly reflect in their ADIT impact numbers that at the time DSU NO rates are reset and the loss of ENO's net-credit ADIT balance would actually affect gas rates (approximately 2028), DSU NO would have new ADIT to partially offset the $58.1 million.[21] ***Thus, while neither party can calculate the exact net ADIT impact, we know it would be less than the amount not transferring to DSU NO,*** which the Advisors have assumed to be $58.1 million.
"DSU NO did not state how much this [goodwill] benefit it would share with ratepayers, but Mr. Watson estimated the maximum rate base credit would be approximately $13.5 million if DSU NO	***Incorrect because the Advisors' calculation is based on the NBV of ENO's rate base without removing the Retained Assets and does not include a tax gross up factor, and the goodwill***

[19] Hearing Exhibit DSU NO – 18, Rejoinder Testimony of David E. Dismukes, Ph.D., DSU NO witness, at 31:9-14 (September 3, 2024)., citing: Texas Senate Special Committee on Hurricane and Tropical Storm Preparedness Recovery and Electricity – YouTube, https://www.youtube.com/watch?v=MpbM2q8YXw8, at 6:47:03.

[20] SWBNO Initial Post-Hearing Brief at 10 (October 15, 2024) (emphasis added).

[21] Hearing Exhibit ENO – 14, Rejoinder Testimony of Jay A. Lewis, DSU NO witness, at 12:12-18 (September 3, 2024).

agreed to credit the entire amount in DSU NO's rate base." Original Brief at 11	***credit is not to rate base but would be a sharing of tax deductions related to goodwill to further mitigate the revenue requirement impact of ENO ADIT not transferring at closing.*** Advisors' maximum goodwill credit understates the amount of goodwill to be created from the Transaction because the Advisors take the purchase price less ENO's NBV without removing Retained Assets.[22] The Advisors previously acknowledged Retained Assets should be removed.[23] Further, the Advisors credit is not grossed up for tax purposes. When these issues are corrected, the estimated annual goodwill amortization credit to revenue requirement is $1.8 million. In addition, the Advisors refer to the goodwill benefit as a credit to rate base; however, DSU NO has indicated that it will not seek recovery of the goodwill, which when combined with the amortization of that goodwill for tax purposes will result in tax deductions related to goodwill, and DSU NO is open to sharing with customers a portion of this tax benefit to further mitigate the *<u>net revenue requirement impacts</u>* of ENO ADIT not transferring at closing.[24]
"The Joint Applicants did not provide any analyses quantifying the long-term ratepayer impacts." *Original Brief at 26*	***<u>Incorrect</u>*** **because DSU NO has provided a number of forecasts and estimates of rate benefits.** DSU NO has quantified several of the long-term benefits of the Transaction, as follows: (1) a 22% or $5.7 million lower 10-year Total Cost of Ownership as compared to the Entergy on-premises IT system platform;[25] (2) positive benefit-cost ratio supporting IT investment ranging from $12.8 million in net benefits or a 3.60 benefit-cost ratio (if ENO only allocation is applied), transaction economic development benefits attributed to the Transition Plan are applied, the analysis calculates $16.5 million in net benefits or a 4.36 benefit-cost ratio (if total Entergy Transaction is applied), and

[22] Hearing Exhibit ADV-12, Surrebuttal Testimony (HSPM-CS) of Byron S. Watson, Advisors witness, at 33:6-14 (August 5, 2024).

[23] Hearing Exhibit ADV-11, Direct Testimony (HSPM-CS) of Byron S. Watson, Advisors witness, at 46:18-47:5 (May 31, 2024).

[24] Hearing Exhibit DSU NO-12, Rebuttal Testimony (Public Redacted) of Jay Lewis, DSU NO witness, at 15-16 (June 28, 2024).

[25] Hearing Exhibit DSU NO – 6, Rebuttal Testimony (Public Redacted) of Brian K. Little, DSU NO witness, at 21:5-7 (June 28, 2024). Total Cost of Ownership ("TCO") is an estimate of an organization's overall expected spend to purchase, configure, install, use, monitor, maintain, optimize, and retire a product or service. *Id*. at 20:19-20.

	$33.1 million in net benefits or a 7.72 benefit-cost ratio (if the CenterPoint and Entergy transactions are considered together);[26] (3) approximately $10 million in O&M savings (forecasted 2026) from lower growth in O&M expenses compared to ENO's historical annual O&M growth of over 8.5% CAGR,[27] and (4) up to 10% savings in shared services O&M (with CenterPoint transaction closing).[28]
	CONFUSING
"…the Council's Utility Advisors ("Advisors") recognize the state and local economic benefits of the Gas Transaction, but note that these types of benefits do not directly translate in rate impacts …" *Original Brief at 2*	***Confusing because the significant economic benefits of the Transaction benefit all New Orleans citizens, who are gas ratepayers.*** While the economic benefits of the Transaction may not translate into a gas rate, they still benefit gas customers; further, existence of ratemaking benefits is only one of 18 factors.[29]
"… the Gas Transaction, as proposed, will result in quantifiable net ratepayer harm." *Original Brief at 14*	***Confusing because the Advisors do not and could not know at this time that the Transaction will result in "quantifiable net ratepayer harm."*** Net ratepayer impact cannot be known until the rate case when more data is available to support the benefits of the Transition Plan Costs - - *which the Advisors acknowledged in their Original Brief*.[30] Further, see Graph No. 1 of DSU NO Reply Brief (estimated annual incremental costs and potential savings of Transaction for hypothetical 2028).
"The Joint Application and associated testimony by DSU NO offered no estimate of bill impacts related to the Gas Transaction." *Original Brief at 15*	***Confusing as DSU NO has not requested a rate change in this proceeding, so there is no rate impact to estimate.***
	CONFLICTING
"On multiple occasions, the Louisiana Supreme Court has described the regulatory powers of the Louisiana Public Service Commission ('LPSC') (outside of New Orleans) and the Council (within New Orleans) as 'broad and independent' over public utilities. The Court has labelled the regulator's jurisdiction over public utilities in Louisiana as 'plenary.'" *Brief at 5, internal citations omitted*	***Conflicting* as while on one hand the Advisors argue the broad authority of the Council, on the other hand the Advisors claim the Council will have limited authority in the future rate case.** Despite representing that the Council has broad jurisdiction and plenary authority over public utilities, the Advisors argue the Council should adopt a mitigation framework in this proceeding that pre-determines which benefits can be included

[26] Hearing Exhibit DSU NO – 15, Rebuttal Testimony (Public Redacted) of David E. Dismukes, Ph.D, DSU NO witness, at 53:1-7 (June 28, 2024) (as corrected July 17, 2024).

[27] Hearing Exhibit DSU NO – 8, Rebuttal Testimony (HSPM-CS) of Brian K. Little, DSU NO witness, at 24:3-8 (June 28, 2024).

[28] Hearing Exhibit DSU NO – 6, Rebuttal Testimony (Public Redacted) of Brian K. Little, DSU NO witness, at Exhibit BL-16 (June 28, 2024).

[29] Restructuring Resolution at factor "(e)."

[30] Advisors Original Brief at 37 (October 15, 2024).

	in a future proceeding in support of recovery of Transition Plan Costs *(i.e.,* only IT savings) and to pre-judge whether certain types of benefits are reasonable and reliable for the Council to consider (*i.e.*, only actual, quantifiable savings without use of studies / estimates).[31] ***The Advisors' mitigation framework is inconsistent with past practice of the Council to consider a broader set of benefits to support ENO's spend on advanced metering technology,[32] and to recognize the benefits of more resilient utility infrastructure.[33]*** Rather, the Advisors insistence on limiting the type of potential benefits that DSU NO can support in a future proceeding only serves to tie the hands of the Council in the future proceeding, which is inconsistent with the Council's broad and plenary authority.
"While these [quantification of ratepayer harm] are estimates at this time, the ratepayer harm that the Advisors' have identified will be certain and calculable at the time of the initial rate case filed by DSU NO, and at the time of the rate actions where rates are determined for ENO electric ratepayers." *Brief at 16*	***<u>Conflicting</u>*** **because on one hand the Advisors claim their impact analysis indicates a quantifiable net ratepayer harm, the Advisors do not include any benefits to quantify a "net" impact and also acknowledge late in their brief that their impact analysis is only an estimate and can only be an estimate at this time.[34]**

[31] Hearing Exhibit ADV – 4, Surrebuttal Testimony of Joseph W. Rogers (Public Redacted), Advisors witness, at 27:17-28:17 (August 5, 2024).

[32] Docket No. UD-16-04, *Application of Entergy New Orleans, Inc. for Approval to Deploy Advanced Metering Infrastructure, and Request for Cost Recovery and Related Relief*, Resolution and Order No. R-18-37 (February 8, 2018) ("*AMI Resolution and Order*"); Docket No. UD-17-02, *Application of Entergy New Orleans, Inc. for Approval Regarding Continued Participation in the Midcontinent Independent System Operator, Inc. Regional Transmission Organization,* Resolution and Order No. R-17-627 (December 14, 2017) ("*MISO Resolution and Order*").

[33] AMI Resolution and Order (February 8, 2018).

[34] Advisors Original Brief at 37 (October 15, 2024).