IN THE UNITED STATES BANKRUPTCY COURT
FOR THE SOUTHERN DISTRICT OF TEXAS
HOUSTON DIVISION

In re:	Chapter 11
ZACHRY HOLDINGS, INC., *et al.*,[1]	
Reorganized Debtors.	Case No. 24-90377
ZACHRY HOLDINGS, INC., *et al.*,	
Plaintiffs,	
v.	Adv. Pro. No. 25-03025 (MI)
OMAHA PUBLIC POWER DISTRICT,	
Defendant.	

REORGANIZED DEBTORS' MOTION FOR PARTIAL SUMMARY JUDGMENT RE LIQUIDATED DAMAGES

[1] The last four digits of Zachry Holdings, Inc.'s tax identification number are 6814. A complete list of each of the Reorganized Debtors in these chapter 11 cases and the last four digits of their federal tax identification numbers may be obtained on the website of the Reorganized Debtors' claims and noticing agent at https://www.veritaglobal.net/ZHI. The location of the Reorganized Debtors' service address in these chapter 11 cases is P.O. Box 240130, San Antonio, Texas 78224.

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Plaintiffs Zachry Holdings, Inc., Zachry Industrial, Inc. ("Zachry"), and their debtor affiliates (collectively, the "Reorganized Debtors") respectfully move this Court pursuant to Rule 56 of the Federal Rules of Civil Procedure made applicable herein by Rule 7056 of the Federal Rules of Bankruptcy Procedure, and pursuant to this Court's invitation at the hearing held on April 12, 2025, for summary judgment on the First Cause of Action in the Reorganized Debtors' First Amended Adversary Complaint [Docket No. 22] ("Complaint"), declaring that the liquidated damages provision in Article XI of the Engineer, Procure, and Construct Contract between Zachry and Defendant Omaha Public Power District ("OPPD"), as amended for a second time in August 2024 (the "Liquidated Damages Provision"), is an unenforceable penalty. In support of their motion, the Reorganized Debtors would show the following:

INTRODUCTION

This action stems from a dispute over the cause of, and damages associated with, a delay in the substantial completion of two electric generating stations and associated sub-stations that Zachry has built for OPPD, namely, Standing Bear Lake Station and Turtle Creek Station. The parties entered into the Engineer, Procure, and Construct Contract in September 2021 ("Original EPC"); the EPC was amended twice for the purpose, among others, to extend the Guaranteed Substantial Completion Dates of the Stations. At the time of the second amendment in August of 2024 ("Second Amended EPC"), the Reorganized Debtors were in the thick of these bankruptcy proceedings, and the Stations were more than 90 percent complete.

Even so, the Liquidated Damages Provision in the Second Amended EPC increased daily charge for delay of each station by increments of $100,000, $125,000, or $150,000 — with no stated justification. Because delay-related damages with respect to power plants are not difficult to ascertain, and because the Liquidated Damages Provision of the Second Amended EPC is not a reasonable forecast of just compensation for delay, the Reorganized Debtors move for partial summary judgment on their First Claim for Relief. Specifically, Reorganized Debtors seek a declaratory judgment that the Liquidated Damages Provision is an unenforceable penalty under Nebraska law. *See* Complaint at 36–39, ¶¶ 112–118.

RELEVANT FACTS AND PROCEEDINGS

A. Standing Bear Lake and Turtle Creek Generating Stations

As described by OPPD, the Original EPC is the means by which "OPPD contracted with Zachry to provide services for all activities associated with designing, procuring, installing, starting up, and testing two (2) power plant sites: (i) the Standing Bear Lake Station . . . ; and (ii) the Turtle Creek Station," both "located in the Omaha metropolitan area." OPPD Motion to Dismiss [Docket No. 11] at 3 ("Motion to Dismiss"). As described by the Original EPC, both Stations will generate electricity by means of multiple generating units whose "[p]rimary fuel . . . will be pipeline quality natural gas." Exhibit B, at 6, 8.

Crucially, in contrast to a "baseload" facility that runs more frequently, each Station will "be operated as a regulating and **peaking** power Facility, with the [generators] operating in a cyclic manner to support grid demands." *Id.* (emphasis added). That is to say, Standing Bear Lake Station and Turtle Creek Station are designed to be generating "units that are **only utilized during peak hours**." Exhibit G, at 14 (emphasis added) (OPPD's

definition of "Peaker" facility). Specifically, OPPD anticipates the Stations to operate only 15% of the time, primarily during summer months when demand for electricity is typically higher in Nebraska and the broader system in which OPPD participates. *See* Exhibit I, at 11, ¶ 31 (declaration of expert Tanya Bodell, citing OPPD webpages).

B. OPPD's costs since December 2024

As executed in August 2024, the Second Amended EPC set December 30, 2024 as the Substantial Completion Date for Standing Bear Lake Station and December 16, 2024 as such date for Turtle Creek Station. *See* Exhibit E, at 4, ¶ 8. Unfortunately, the Stations were not substantially completed by those dates.[2] Consequently, in lieu of the (presumed) lower-cost electricity products that would have been generated by the two Stations since December 2024, OPPD has been unable to sell the energy from the plant during peak hours in the winter and spring, and it may have needed to acquire (presumed) higher-cost capacity and ancillary services in order to fulfill its obligations to the Southwest Power Pool ("SPP," a regional electricity market in which OPPD participates). Therefore, as elaborated in the Argument below, OPPD's (presumed) damages for Zachry's alleged delay in completing the Stations are measured by the additional costs that OPPD incurred, i.e., the difference between the higher purchase costs that OPPD **actually** incurred and the lower generation costs that OPPD **would have** incurred had the Stations been completed.

We first examine OPPD's actual purchase costs, including the ease of estimating them beforehand. We then examine the costs that OPPD would have incurred for generating

[2] As set forth in the Complaint, the Reorganized Debtors allege that the delays in achieving Substantial Completion have been, and continue to be, caused by OPPD and the contractors under its control.

winter and spring electricity products had each Station been operational on its respective Substantial Completion Date.

1. OPPD's Actual Purchase Costs and their estimation beforehand

The actual cost of OPPD's purchases of electricity products that are not covered by what the two Stations would have produced is readily available in OPPD's "tradebook," along with a key input to their production costs (e.g., fuel). Yet despite Zachry's requests, OPPD refused to provide that information. *See* Exhibit H.

Even in the absence of that information, however, it is fairly easy to estimate OPPD's higher purchase costs using two simple inputs:

- quantity: the amount of energy, ancillary services, and capacity that the Stations would have produced; and
- price: the cost of those electricity products, either under contracts between OPPD and suppliers of those electricity products or on the spot market.

See Exhibit I, at 21, ¶ 50. The prices for energy and ancillary services can be obtained from historical data that is publicly available from SPP; other pricing information is necessarily in the possession of OPPD or can be estimated using neighboring markets. *See id.* at 21, ¶¶ 52–53. Using that data, Actual Purchase Costs can be **calculated** now using a simple spreadsheet model. *See id.* at 21, ¶ 54.

Furthermore, OPPD's Actual Purchase Costs (i.e., the costs of replacing the power not generated by the Stations) could have been **estimated** to a high degree of certainty in August 2024. Indeed, "these types of 'ex-ante' calculations are performed all the time by industry investors and market participants." *Id.* at 32, ¶ 87. For price, one could simply use prices from the "SPP North" futures market for electricity (supplemented by historical data

on "price shapes"). *See id.* at 32, ¶ 88(1)(a). For quantity, one could simply use the size of the Stations and projected price spreads to estimate when each of the Stations would operate — an estimation that utilities like OPPD routinely undertake as part of their budgeting and procurement process, as well as their planning process to meet their energy and reserve requirements. *See id.* at 7, ¶ 21(7); Exhibit G, at 27–28 (explaining Cost of Service Studies that OPPD conducts to comply with its statutory duty to set fair and reasonable rates). Zachry's experts have performed this ex-ante estimation. *See* Exhibit I, at 33, ¶ 90.

2. OPPD's Estimated Generation Costs both now and in August 2024

Estimating the costs that OPPD would have incurred for generating winter and spring peak load electricity had Standing Bear Lake Station and Turtle Creek Station been operational may be accomplished now based on three inputs:

- quantity: the amount of energy, ancillary services, and capacity that the Stations would have produced (exactly the same as for actual costs above);
- fuel cost: the cost of the natural gas required to generate the foregoing quantity of electricity, which has two components:
    - quantity: the volume of that natural gas, which depends on the "heat rates" at which the engines at each Station transform gas into electricity; and
    - price: the market price for that natural gas;
- non-fuel cost: the variable operations-and-maintenance costs to run the generating equipment at each Station.

See Exhibit I, at 74–82 (Sections E.1.2–E.1.6). As noted, the quantity of electricity is the same for both the real world in which the Stations are not fully operational (referred to as the "Actual World" in Exhibit I) and the hypothetical world in which the Stations were fully operational in December 2024 (referred to as the "But-for World" in Exhibit I). The

heat rates of the generating equipment at each Station are generally known and are in any case available in the technical specifications and thermal guarantees from the manufacturer; and the market price of natural gas is historical data that is publicly available from public and proprietary data sources. *See id.* at 74–76, 80–82 (Sections E.1.3 and E.1.6). All of these inputs to calculate damages are necessarily in OPPD's possession. Combining all of this information (or an estimate based on industry data) in a relatively simple spreadsheet model yields a reasonable, transparent, and replicable cost estimate. *See id.* at 21, ¶ 54.

Making the foregoing estimate in August 2024 would have been essentially similar, but with two differences. First, as with estimating the Actual Purchase Costs, an estimate of when the Stations would have produced in response to projected market price spreads can be made using a simple spreadsheet model. *See id.* at 21, ¶ 51. Second, for the prices of both electricity and natural gas, one would use (instead of historical data) monthly futures data shaped by historical price shapes. *See id.* at 88–93 (Sections E.2.1 and E.2.2). Again, "these types of 'ex-ante' calculations are performed all the time by industry investors and market participants." *Id.* at 32, ¶ 87.

OPPD itself makes these very determinations as part of its annual budgeting process. *See, e.g.*, Exhibit F, at 33 (OPPD's 2025 Corporate Operating Plan, projecting customer demand and differences from 2024 in OPPD's budget for purchases of power and operations and maintenance costs resulting from the availability of the Standing Bear Lake and Turtle Creek Stations). And again, Zachry's experts have performed this ex-ante estimation for both Standing Bear Lake Station and Turtle Creek Station. *See* Exhibit I, at 33, ¶ 90.

C. Liquidated Damages Provision

The Original EPC contains a Liquidated Damages Provision. But that contract was executed prior to work commencing on the Stations and years before the Stations became operational. As noted above, at the time of the Second Amended EPC, the Stations were more than 90% complete. In addition to revising the Substantial Completion Date for each Station, the Second Amended EPC also revised the Liquidated Damages Provision:

- For Standing Bear Lake Station, the revised provision imposes a daily charge of "$350,000 per calendar day [for the first 30 days], and $500,000 per calendar day until the Work is accepted as complete."
- For Turtle Creek Station, the revised provision imposes a daily charge of "$250,000 per calendar day [for the first 30 days], and $400,000 per calendar day until the Work is accepted as complete."

Combining these changes yields the following:

Station	Substantial Completion Date	Original Maximum Daily Charge	Current Maximum Daily Charge	Multiple
Standing Bear Lake	December 30, 2024	$250,000	$500,000	2.0
Turtle Creek	December 16, 2024	$100,000	$400,000	4.0

See Exhibit A, at 14–15, art. XI(c)(1)(i)–(ii); Exhibit E, at 3–4, ¶¶ 7–8.

Moreover, "Total liquidated damages in the aggregate for both sites shall not exceed Fifteen percent (15%) of the Contract Price." Exhibit A, at 14, art. XI(a). As adjusted by Change Order No. 1 in November 2023, the Contract Price is $428.7 million. *See* Exhibit D, at 3, ¶ 7. Fifteen percent of that figure is $64.3 million. OPPD has asserted that "if Zachry fails to reach substantial completion of [Turtle Creek Station] by February 14, 2025, and of [Standing Bear Lake Station] by February 28, 2025, respectively" — which did come to

pass — "Zachry will be obligated to pay the remainder of the maximum liquidated damages, totaling fifteen percent (15%) of the total EPC contract price." OPPD Application at 6, ¶ 20. Accordingly, if the Liquidated Damages Provision is enforceable, OPPD's position is that Zachry is liable to OPPD for liquidated damages in the amount of $64.3 million.

D. Proceedings to date

The Reorganized Debtors instituted this adversary proceeding by filing an original complaint against OPPD on February 2, 2025. Docket No. 1. OPPD moved to dismiss, and the Reorganized Debtors filed a First Amended Complaint. Docket Nos. 11 and 22. OPPD recently filed a motion to dismiss the amended complaint. Docket No. 34.

OPPD also moved to withdraw the reference and separately to transfer this action to the District of Nebraska; the Reorganized Debtors filed a combined response; and OPPD filed a reply. Docket Nos. 12, 13, 24, and 31.

In a hearing held on April 12, 2025, the Court invited the Reorganized Debtors to file this motion. Although the Court suggested "voluntary" discovery between the parties, OPPD has spurned Zachry's limited requests for relevant information. *See* Exhibit H.

ARGUMENT
The Liquidated Damages Provision is an unenforceable penalty.

For purposes of this Motion, the sole dispute between the Parties is whether the Liquidated Damages Provision — daily charges that are capped out at $64.3 million — are enforceable "liquidated damages" or instead constitute an unenforceable "penalty."[3] The

[3] The Reorganized Debtors dispute that the delays in achieving the Substantial Completion Dates are caused solely by Zachry. In fact, for the reasons set forth in the Complaint, the delays are caused by OPPD, by OPPD-controlled contractors, or by some combination of both. For purposes of this Motion only the Reorganized Debtors assume arguendo that Zachry breached the Second Amended EPC, and that the Liquidated Damages Provision is triggered.

parties agree that Nebraska law applies to this dispute, and that such law is accurately stated by the federal district court's decision in *Lund-Ross Constructors, Inc. v. Vecino Natural Bridge, LLC*, 2021 WL 6202667, at *4 (D. Neb. Nov. 3, 2021). *See* Motion to Dismiss at 7 (asserting that "Nebraska law governs the [EPC] Contract"); *id.* at 8–9, 11 (favorably citing *Lund-Ross* four times). *Lund-Ross* explains that, in general, "the question whether a sum mentioned in a contract is to be considered as liquidated damages or as a penalty is a question of law." 2021 WL 6202667, at *4 (quoting *Berens & Tate, P.C. v. Iron Mountain Information Management, Inc.*, 747 N.W.2d 383, 387 (Neb. 2008)). In particular,

> [1] if the damages arising from a breach are difficult to ascertain or measure, **and**
>
> [2] if the stipulated amount is either
>
> > [i] a reasonable estimate of the damages that might result from a breach **or**
> >
> > [ii] is reasonably proportional to the actual damages caused by the breach,
>
> the amount will usually be regarded as a provision for liquidated damages.

Id. (emphasis added; cleaned up; quoting *Kozlik v. Emelco, Inc.*, 483 N.W.2d 114, 121 (Neb. 1992)); *accord, e.g., Berens & Tate*, 747 N.W.2d at 387; *In re Papio Keno Club, Inc.*, 247 B.R. 453, 461 (B.A.P. 8th Cir. 2000), *aff'd*, 262 F.3d 725 (8th Cir. 2001).

Therefore, to qualify as true liquidated damages that are enforceable against Zachry, the Liquidated Damages Provision must satisfy **both** the "difficult to ascertain" requirement **and** the "reasonable estimate" or "reasonably proportional" requirement. As explained in the following two parts, the Liquidated Damages Provision satisfies **neither** requirement.

A. Damages of the kind at issue here are not difficult to ascertain or measure.

Under Nebraska law, "the measure of damages for a breach of a contract claim is an amount that would place [the plaintiff] in as good a position as it would have enjoyed if the contract had been performed." *Infogroup, Inc. v. DatabaseLLC*, 956 F.3d 1063, 1068 (8th Cir. 2020) (approving jury instruction so stating; citing *Bachman v. Easy Parking of America, Inc.*, 562 N.W.2d 369, 373 (Neb. 1997)). It is not difficult to state the "position" that OPPD would have enjoyed had the parties achieved the Substantial Completion Dates established by the Second Amended EPC: Standing Bear Lake Station would have been operational on December 30, 2024, and Turtle Creek Station would have been operational on December 16, 2024. *See supra* p. 9 (table). Had that scenario materialized, OPPD would have operated the Stations to produce energy and cover its reserve requirements between those dates and April 15, 2025. In so doing, OPPD would have incurred operational costs in generating peak load electricity at each Station. We shall call those (presumably lower) costs OPPD's "Estimated Generation Costs."

But because of Zachry's (presumed, for present purposes only) breach of the Second Amended EPC, neither Standing Bear Lake Station nor Turtle Creek Station was operational between December 2024 and April 2025. As a result, OPPD was unable to sell energy from those Stations into the market to offset its purchases and may have been required to purchase capacity and regulating reserves from the market to cover its peak load requirements during that period. We shall call those (presumably higher) costs OPPD's "Actual Purchase Costs." To put OPPD in "as good a position" as it would have enjoyed if the Second Amended EPC had been timely performed requires merely subtracting the former from the latter:

Actual Purchase Costs – Estimated Generation Costs = Damages

Are OPPD's Actual Purchase Costs or its Estimated Generation Costs "difficult to ascertain or measure"? In a word, *no*.

1. Actual Purchase Costs

These costs are simply what OPPD actually paid to cover its peak load requirements during the relevant period that it could not cover with its own generation. Whether such out-of-pocket costs were incurred pursuant to one or more contracts entered into before the Second Amended EPC was executed (as alleged in ¶ 44 of the Complaint), or rather simply involved spot purchases, does not matter for present purposes. What matters is only the amount that OPPD paid to suppliers of peak load power that it could not cover with its own generation — a sum that is easily ascertained by examining OPPD's own books.

OPPD refused to provide any financial information from its books. *See* Exhibit H. Even so, Zachry's expert readily estimated OPPD's Actual Purchase Costs using the methodology described in Subsection B.1 above (pp. 6–7). Those costs amount to $25.7 million combined for energy, capacity and ancillary services. *See* Exhibit I, at 28, ¶ 77.

2. Estimated Generation Costs

These costs, though slightly more complicated, are likewise not difficult to ascertain or measure. As described in detail above, they are what it would have cost OPPD to operate Turtle Creek Station and Standing Bear Lake Station during the relevant periods. Zachry's expert readily estimated these costs using the methodology described in Subsection B.2 above (pp. 7–8). Those costs amount to $17.0 million. *See* Exhibit I, at 28, ¶ 77.

Accordingly, it is not difficult to ascertain or measure Damages, which is the simple difference between the two figures, or **$8.7 million**. *See id.*

3. Caselaw

Caselaw confirms that the actual damages arising from Zachry's (presumed) breach are not "difficult to ascertain or measure." On the one hand, these purely numerical calculations based on known historical facts are very different from the "[d]amages for lost profits, missed opportunities, and reputational harm" that *Lund-Ross Constructors* concluded are "hard to quantify." 2021 WL 6202667, at *6. By definition, lost profits and missed opportunities depend on **estimations** of sales or other revenue-generating activities that **might have** happened (but in fact did not happen). Reputational harm is even less amenable to quantification: it is an estimate of a decline in reputation, which might lead in turn to declines in sales or other revenue-generating activities, the magnitude of which must likewise be estimated.

OPPD's Actual Purchase Costs and its Estimated Generation Costs do not share these characteristics: as documented above, they are amenable to quantification; indeed, they have **actually been quantified**. *Cf. Aramark Uniform Services v. Meylan Enterprises, Inc.*, 2007 WL 1532329, at *4 (Neb. Ct. App. May 29, 2007) (finding that damages were difficult to ascertain in part because "there are also several variable factors that prevent Aramark's **overall** damages from being easily ascertained").

On the other hand, the actual damages arising from Zachry's (presumed) breach are very much like the kinds of damages that courts applying Nebraska law have concluded are **not** difficult to ascertain. In *Papio Keno Club*, the court concluded that it —

> would not be difficult to ascertain the actual damages for any of [the alleged] material breaches. The damages incurred by the City for the Debtor's failure to maintain liability insurance would be, at most, the difference between the amount of insurance the Debtor actually maintained and the amount it was required to maintain. Similarly, the damages sustained by the City for the Debtor's failure to maintain a $250,000 letter of credit would be, at most, the difference between the amount available under the letter of credit and $250,000. Furthermore, the damages incurred by the City for the Debtor's failure to timely apply to renew its license easily could be calculated based on the City's average daily share of the gross proceeds for each day that the Debtor was unable to operate because it was without a license.

247 B.R. at 461. Like the City's damages, OPPD's damages can be "calculated," mostly based on the "difference" between one financial figure and another.

Similarly, in *Browning Ferris Industries of Nebraska, Inc. v. Eating Establishment-90th & Fort, Inc.*, 6 Neb. App. 608, 613 (1998), the court concluded that "the actual damages would not be overly difficult to ascertain with some precision if BFI desired to do so. [BFI's district sales manager] testified that BFI was a sophisticated competitor in the disposal industry, with over 3,000 accounts in Nebraska, and had a full staff of accountants. [He] acknowledged that the company could probably determine what the profit was on an average contract." OPPD is likewise a sophisticated participant in the electric utility industry with a full staff of accountants. Doubtless OPPD could determine its Actual Purchase Costs, its Estimated Generation Costs, and the simple difference between those two figures. OPPD's public communications confirm that point. *See, e.g.*, Exhibit F, at 33.

In sum, damages of the kind at issue here are not difficult to ascertain or measure. For that reason alone, the Liquidated Damages Provision is an unenforceable penalty.

B. Alternatively, the amount stipulated in the Liquidated Damages Provision is not a reasonable estimate of, or reasonably proportional to, actual damages.

As quoted above, the party seeking to establish that a stipulated amount qualifies as enforceable liquidated damages must show **both** that the actual damages are difficult to ascertain "and" that such amount is either a reasonable estimate of, or reasonably proportional to, actual damages. *Lund-Ross Constructors*, 2021 WL 6202667, at *4; *Berens & Tate*, 747 N.W.2d at 387 (quoting *Kozlik*, 483 N.W.2d at 121); *cf. Aramark Uniform Services*, 2007 WL 1532329, at *4 (enforcing liquidated damages provision only after finding **both** "sufficient evidence that Aramark's damages were not easily ascertainable" **and** "sufficient evidence that the actual damages were reasonably related to the liquidated damages"). That OPPD can make neither showing provides an independent reason for concluding that the Liquidated Damages Provision constitutes an unenforceable penalty.

1. The stipulated amount was *not* a reasonable estimate of OPPD's likely damages.

Whether a stipulated amount is a reasonable estimate of likely damages is to be "determined [as of] the time the contract was entered." *Aramark Uniform Services*, 2007 WL 1532329, at *3 (emphasis deleted). Here, that was August 2024, when the Second Amended EPC was executed.

First, there is no indication that Liquidated Damages Provision is an estimate at all, let alone a reasonable one. *Cf. Kealy v. Harter*, 682 F.2d 198, 200 n.2 (8th Cir. 1982) (per curiam) (applying Nebraska law and opining that the "reasonable estimation" precept "require[s] that the parties make a good faith attempt to predict damages"). To be sure, the

Original EPC recites in Article XI(a) that "both parties agree that the liquidated damages provisions in this Article XI are reasonable and appropriate measures of the damages for such completion and performance shortfalls, and are not a penalty." But nothing in the Original EPC or in the Second Amended EPC — or any extrinsic evidence of which we are aware — provides a basis for viewing the dollar figures as an actual estimate or prediction. *Cf. Hanover Insurance Co. v. Binnacle Development, LLC*, 493 F. Supp. 3d 585, 591 (S.D. Tex. 2020) (finding no "reasonable forecast" of actual damages where the "evidence shows that no study or analysis went into setting $2,500 per diem as the delay fee"), *aff'd*, 57 F.4th 510 (5th Cir. 2023).

Second, the Original EPC and the Second Amended EPC indicate a lack of reasonableness on their face. Article XI(c)(1) and (2) originally imposed a maximum daily charge of $250,000 for failing to timely complete Standing Bear Lake Station and of $100,000 for failing to timely complete Turtle Creek Station. For the former, charges were imposed beginning May 1, 2023; for the latter, beginning August 18, 2023. *See* Exhibit C (specifying the two respective "Substantial Completion Dates"). The Second Amended EPC **doubled** the maximum daily charge for Standing Bear Lake Station (to $500,000) and **quadrupled** it for Turtle Creek Station (to $400,000). For the former, the higher charges were imposed beginning December 30, 2024; for the latter, beginning December 16, 2024.

We are aware of no explanation for these massive increases except to impose a hefty penalty for delay. Certainly, the increases cannot be justified by seasonal variation. To the contrary, it is conceivable that delays would be more costly to OPPD in the summer (when peak demand for electricity is greater, and spot-market electricity costs are correspondingly

higher) than in the winter (when peak demand is lesser, and such costs are correspondingly lower). *See* Exhibit I, at 11, ¶ 31. But the change from the Original to the Second Amended EPC reflects **precisely the opposite**: lower estimated electricity costs in summer and higher estimated electricity costs in winter. On its face, therefore, this is simply not a **reasonable** estimate. *See id.* at 18–19, ¶ 44(2) (opinion of Zachry's expert that this change is "counter-intuitive to the summer peaking nature of the SPP market" and is thus "not reasonable").

Third, as described above (p. 9), just 30 days after the Substantial Completion Date for each Station, the daily charge for that Station "ratchets up" by $100,000. Together with other features of the Liquidated Damages Provision, such a "round-numbered increase . . . completely disconnects the Liquidated Damages provisions from economic harm actually incurred by OPPD." Exhibit I, at 13, ¶ 35. This is yet another reason why the Provision is, on its face, "an unreasonable way to estimate economic damages." *Id.*

Fourth, as detailed in Section B above (pp. 5–8), using publicly available historical data and prices from robust futures markets, it was feasible **in August 2024** to make reasonable estimates of both Actual Purchase Costs and Estimated Generation Costs rather than merely fabricate large round numbers. Zachry's experts did just that, yielding estimates of total Damages of between $6.7 and $17.0 million. *See* Exhibit I, at 33, ¶ 90. Compare that to the Liquidated Damages Provision's "estimate" of $64.3 million — a sum that is between four and nine times too high!

For these many reasons, the amount stipulated in the Second Amended EPC was not a reasonable estimate of OPPD's likely damages.

2. The stipulated amount is *not* reasonably proportionate to OPPD's actual damages.

Nor was that amount reasonably proportionate to OPPD's actual damages. Based on a model using assumptions favorable to OPPD (and without regard to any available defenses), Zachry's experts have calculated that OPPD theoretically sustained actual damages though April 15, 2025 of just under $8.7 million. *See* Exhibit I, at 28, ¶ 77. Yet the amount yielded by the Liquidated Damages Provision tops $64.3 million, a multiple of **roughly 7.4** and a windfall to OPPD of **more than $55 million**. Almost by definition, that multiple is not reasonably proportionate, and that windfall is not reasonable. The caselaw addressing this prong of the test accords with that conclusion:

- **2.2 multiple**, *see Computer Support Services, Inc. v. Vaccination Services of America, Inc.*, 2017 WL 2399486, at *5 (Neb. Ct. App. May 23, 2017) (not reasonably proportionate where liquidated damages of $45,500 exceeded actual damages of only $21,045);

- **$71K windfall**, *see Papio Keno Club*, 247 B.R. at 461 (not reasonably proportionate where liquidated damages of $71,340 are contrasted with no actual damages);

- **$65K windfall**, *see Kealy*, 682 F.2d at 199–200 (not reasonably proportionate where liquidated damages of $65,000 are contrasted with no actual damages).

- **$900K windfall**, *see Hanover Insurance*, 493 F. Supp. 3d at 591 (finding an "ultimate disproportionality between the damages imposed by the liquidated-damages clauses and the actual damages" where "actual damages are $0 and liquidated damages are $900,000").[4]

[4] Decisions from other jurisdictions applying essentially the same test are in accord. *See, e.g., Trustees of Columbia University v. D'Agostino Supermarkets, Inc.*, 36 N.Y.3d 69, 80 (2020) (concluding that because a liquidated damages provision "calls for a sum **more than sevenfold** the amount due if defendant had complied fully with the [contract]," the court "cannot enforce such an obviously and grossly disproportionate award" (emphasis added)); *Newark Shopping Center Owner, L.L.C. v. Saudades Group, LLC*, 2025 WL 655063, at *9 (Del. Super. Ct. Feb. 26, 2025) (finding a violation of the "reasonably proportionate" standard where the liquidated sum was "**more than four times** higher than the maximum" supported by testimonial evidence (emphasis added)); *Garden Ridge, L.P. v. Advance International, Inc.*, 403 S.W.3d 432, 441 (Tex. App.—Houston [14th Dist.] 2013, pet. denied) (holding that defendant had proved that the liquidated sum of $79,457 was "unreasonably large when compared to [plaintiff's] actual damages of zero").

For all these reasons, the amount stipulated in the Second Amended EPC was not reasonably proportionate to OPPD's actual damages, if any. Because that amount was likewise not a reasonable estimate of OPPD's likely damages, OPPD cannot satisfy the second independent requirement for establishing that the Liquidated Damages Provision is enforceable. Accordingly, the provision constitutes an unenforceable penalty.

C. OPPD's contrary argument lacks merit.

OPPD has previously contended that the "liquidated damages provision in the [EPC] Contract is enforceable." Motion to Dismiss at 7 (section heading). In so contending, OPPD advances essentially a single argument: the Liquidated Damages Provision is enforceable **simply and solely** because the Original EPC provides that the parties "acknowledge that actual damages incurred by [OPPD] . . . would be difficult to determine and that both parties agree that the liquidated damages provisions in this Article XI are reasonable and appropriate measures of the damages for such completion and performance shortfalls, and are not a penalty." *Id.* at 10 (quoting Exhibit A, at 14, art. XI(a)).

That is not the law. OPPD urges that, as "stated in *Lund-Ross*, Zachy should not be 'let off the hook' by this Court by its attempt to ignore the explicit provisions it agreed to be bound by in the Contract, including the Second Amendment." *Id.* at 11 (quoting *Lund-Ross*, 2021 WL 6202667 at *5). But *Lund-Ross* actually held that when "the parties are experienced in business, the damages are economic, and the parties had fair opportunity to consider the agreement, Nebraska courts have been **reluctant** to let them off the hook." 2021 WL 6202667 at *5 (emphasis added; cleaned up). Perhaps **reluctant**, but given the above-cited caselaw, obviously **not categorically opposed**.

Therefore, as *Lund-Ross* observed, the Nebraska Supreme Court has "upheld awards of liquidated damages" **not** in every case but rather in those cases "where the damages were uncertain, and the parties' stipulated damages were reasonable." *Id.* As that court itself has repeatedly opined, it has "consistently upheld the right of contracting parties to privately bargain for the amount of damages to be paid in the event of a breach of contract, **provided the stipulated sum is reasonable in light of the circumstances**." *Berens & Tate*, 275 Neb. at 430–31 (emphasis altered; quoting *Reichert v. Rubloff Hammond, L.L.C.*, 264 Neb. 16, 24 (2002), in turn quoting *Kozlik*, 240 Neb. at 535).

Lund-Ross also observed that the "Nebraska Supreme Court has been **pretty clear** about how to determine whether a stipulated amount is liquidated damages or a penalty," namely, the two-part test quoted on Page 11 above and applied herein. 2021 WL 6202667, at *4 (emphasis added). The numerous decisions discussed above, including one from the Bankruptcy Appellate Panel of the Eighth Circuit, make clear that courts applying Nebraska law do not hesitate to nullify liquidated damage clauses when they fail the governing two-part test — as the Liquidated Damages Provision fails here.

Finally, we note OPPD's assertion — unsupported either conceptually or with an offer of proof — that "OPPD's damages are enormous." Motion to Dismiss at 11. But we have shown that, at least in proportion to the charges imposed by Article XI of the Second Amended EPC, that is simply false. We have also shown that, whatever their magnitude, OPPD's actual damages were **not** difficult to ascertain or measure — an independent reason to declare the charges to be unenforceable penalty.

CONCLUSION

For these reasons, the Liquidated Damages Provision of the Second Amended EPC is an unenforceable penalty under governing Nebraska law, and the Court should grant the Reorganized Debtors partial summary judgment so declaring.

Dated: April 28, 2025

Respectfully submitted,

/s/ *John B. Thomas*

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CERTIFICATE OF SERVICE

I certify that on this day, a copy of the foregoing pleading was filed electronically with the Clerk of Court using the CM/ECF system. Notice of this filing will be sent to all counsel of record by operation of the court's electronic filing system.

Dated: April 28, 2025

/s/ *John B. Thomas*
John B. Thomas

EXHIBITS

A. Excerpts of EPC Contract (Sept. 2021).

B. Excerpts of Exhibit B to EPC Contract.

C. Excerpts of Exhibit E to EPC Contract.

D. Change Order No. 1 (Nov. 9, 2023).

E. Amendment No. 2 to EPC Contract (Aug. 2024).

F. Excerpts of OPPD 2025 Corporate Operating Plan (Dec. 19, 2024), https://bit.ly/3GDMfF3.

G. Excerpts of OPPD Rate Fundamentals Report (Jan. 9, 2025), https://bit.ly/4cQe6hp.

H. Letter from OPPD's counsel to Zachry's counsel (Apr. 22, 2025).

I. Declaration of Tanya Bodell (Apr. 28, 2025).

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FOR EXECUTION

ENGINEER, PROCURE, AND CONSTRUCT CONTRACT FOR OMAHA PUBLIC POWER DISTRICT STANDING BEAR LAKE AND TURTLE CREEK GENERATING STATIONS

CONTRACT NO. 263406

September 21, 2021

EXHIBIT
A

ARTICLE XI - LIQUIDATED DAMAGES.

(a) The Contractor and the District acknowledge that actual damages incurred by the District as a result of the Contractor's failure to meet the Guaranteed Substantial Completion Dates and Performance Guarantees would be difficult to determine and that both parties agree that the liquidated damages provisions in this Article XI are reasonable and appropriate measures of the damages for such completion and performance shortfalls, and are not a penalty. Total liquidated damages in the aggregate for both sites shall not exceed Fifteen percent (15%) of the Contract Price.

(b) On or before March 31, 2023, EPC Contractor, OFE Suppliers and OPPD shall meet and confer regarding the status of Acceptance Tests and progress toward meeting the Guaranteed Substantial Completion Date(s), and EPC Contractor and Suppliers shall commit in writing that the Work will be completed by the Guaranteed Substantial Completion Date(s). Failure to meet the Guaranteed Substantial Completion Date(s) shall be subject to the provisions of subsection (c)(1) below. Such provisions shall be the sole and exclusive remedy for any such failure.

(c) Contractor's failure to meet the Guaranteed Substantial Completion Date(s) and/or Performance Guarantees shall result in the following liquidated damages; provided, however, if the Work is delayed by the District or other contractors, Contractor shall nevertheless continue to perform the Work in accordance with the Project Schedule, however Contractor may be entitled to a Change Order if price and schedule are impacted. Acceptance by the District of ongoing monthly liquidated damage payment shall in no event constitute a waiver of the District's right to future liquidated damage payments or operate as an accord and satisfaction of the District's right to future liquidated damage payments or in any other manner prejudice the District's right to future liquidated damage payments. The District's damages arising from claims or causes other than failure to achieve the Guaranteed Substantial Completion Date(s) and/or Performance Guarantees shall be limited only by Section 33 (Limitation of Liability) of the General Conditions.

(1) Delay in Completion of Work

(i) If the Contractor fails to complete the Work on or before the Guaranteed Substantial Completion Date, for SBLS, as a predetermined reasonable and sole and exclusive remedy for such delay, the Contractor shall be subject to liquidated damages as follows: For each calendar day beyond the Guaranteed Substantial Completion Date for SBLS that the Work is not completed, $125,000 per calendar day through May 15, 2023, and $250,000 per calendar day, from May 16, 2023, until the Work is accepted as complete. There shall be an overall sub-cap on this liability equal to ten percent (10%) of the Contract Price.

(ii) If the Contractor fails to complete the Work on or before the Guaranteed Substantial Completion Date, for TCS, as a predetermined reasonable and sole and exclusive remedy for such delay, the Contractor shall be subject to liquidated damages as follows: For each calendar day

beyond the Guaranteed Substantial Completion Date for TCS that the Work is not completed, $50,000 per calendar day, through September 1, 2023, and $100,000 per calendar day, from September 2, 2023, until the Work is accepted as complete. There shall be an overall sub-cap on this liability equal to ten percent (10%) of the Contract Price.

(2) Performance Guarantees. The Contractor shall have reasonable access to the Sites as mutually agreed between the parties, to implement corrective action in order to demonstrate Performance Guarantees. Any release of retainage will be in accordance with Article IV, Section (b). With respect to Performance Guarantees, should the District and the Contractor agree that any remedy is impractical, uneconomic or inexpedient, or should Contractor not make any such remedy, or should Contractor still fail to satisfy such Performance Guarantees following all attempts to remedy, it is agreed that the District's loss would be difficult to determine. Accordingly, after successful completion of all of the tests and retests specified, the District and Contractor agree that, as a predetermined reasonable and sole and exclusive remedy for any such loss, Contractor will pay to the District, as liquidated damages and not as a penalty, the liquidated damages, if any, determined in accordance with the following provisions.

If the Contractor cannot demonstrate conformance with the Thermal Performance Guarantees by passing the Acceptance Tests on or before the Guaranteed Substantial Completion Date, for either or both SBLS or TCS, the Contractor shall pay daily liquidated damages as follows:

Thermal Performance Guarantee	Liquidated Damages
Balance of Plant Auxiliary Power – Natural Gas – SBLS	One Thousand Five Hundred Dollars ($1,500) for each kW (or prorated fraction thereof) by which the auxiliary power is greater than the guaranteed value.
Balance of Plant Auxiliary Power – Fuel Oil – SBLS	One Thousand Five Hundred Dollars ($1,500) for each kW (or prorated fraction thereof) by which the auxiliary power is greater than the guaranteed value.
Balance of Plant Auxiliary Power – Natural Gas – TCS	One Thousand Five Hundred Dollars ($1,500) for each kW (or prorated fraction thereof) by which the auxiliary power is greater than the guaranteed value.
Balance of Plant Auxiliary Power – Fuel Oil – TCS	One Thousand Five Hundred Dollars ($1,500) for each kW (or prorated fraction thereof) by which the auxiliary power is greater than the guaranteed value.

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(d) Liquidated damages shall be paid to the District by the Contractor at the end of each month in which any liquidated damages accrue, or the District may, at its option, offset any accrued liquidated damages against amounts due and payable to the Contractor under the Contract Documents.

(e) Specific Performance. It is hereby agreed by the District and Contractor that the Work to be performed under the Contract Documents is unique in nature. Consequently, except as to breaches for which a remedy is specified in the Agreement, if Contractor breaches the Contract Documents, the District shall have the right to require specific performance at the District's option. Such option by the District shall not limit the District's right to any and all damages recoverable under the Agreement.



2023 GENERATION ADDITION

ENGINEER, PROCURE, CONSTRUCT

EXHIBIT B - TECHNICAL SPECIFICATION

EXHIBIT

B

OMAHA PUBLIC POWER DISTRICT
2023 GENERATION ADDITION

ENGINEER, PROCURE, CONSTRUCT
EXHIBIT B – TECHNICAL SPECIFICATION

OPPD Contract No.:	263406
Document No.:	10214444-ZP-M0102
Issue:	For Contract
Revision:	1

Prepared By

HDR

SECTION 01 – OVERVIEW

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1 OVERVIEW

1.1 INTRODUCTION

Owner: Omaha Public Power District – OPPD

The Owner's project consists of two power plant Sites. The northern Site, hereafter referred to as the "Standing Bear Lake Station" (SBLS), will use reciprocating internal combustion engine (RICE) generator sets as the generation technology; the southern Site, hereafter referred to as the "Turtle Creek Station" (TCS), will use combustion turbine generators as the generation technology.

Further description of the two project Sites follows.

1.2 STANDING BEAR LAKE SITE

Facility Name: Standing Bear Lake Station

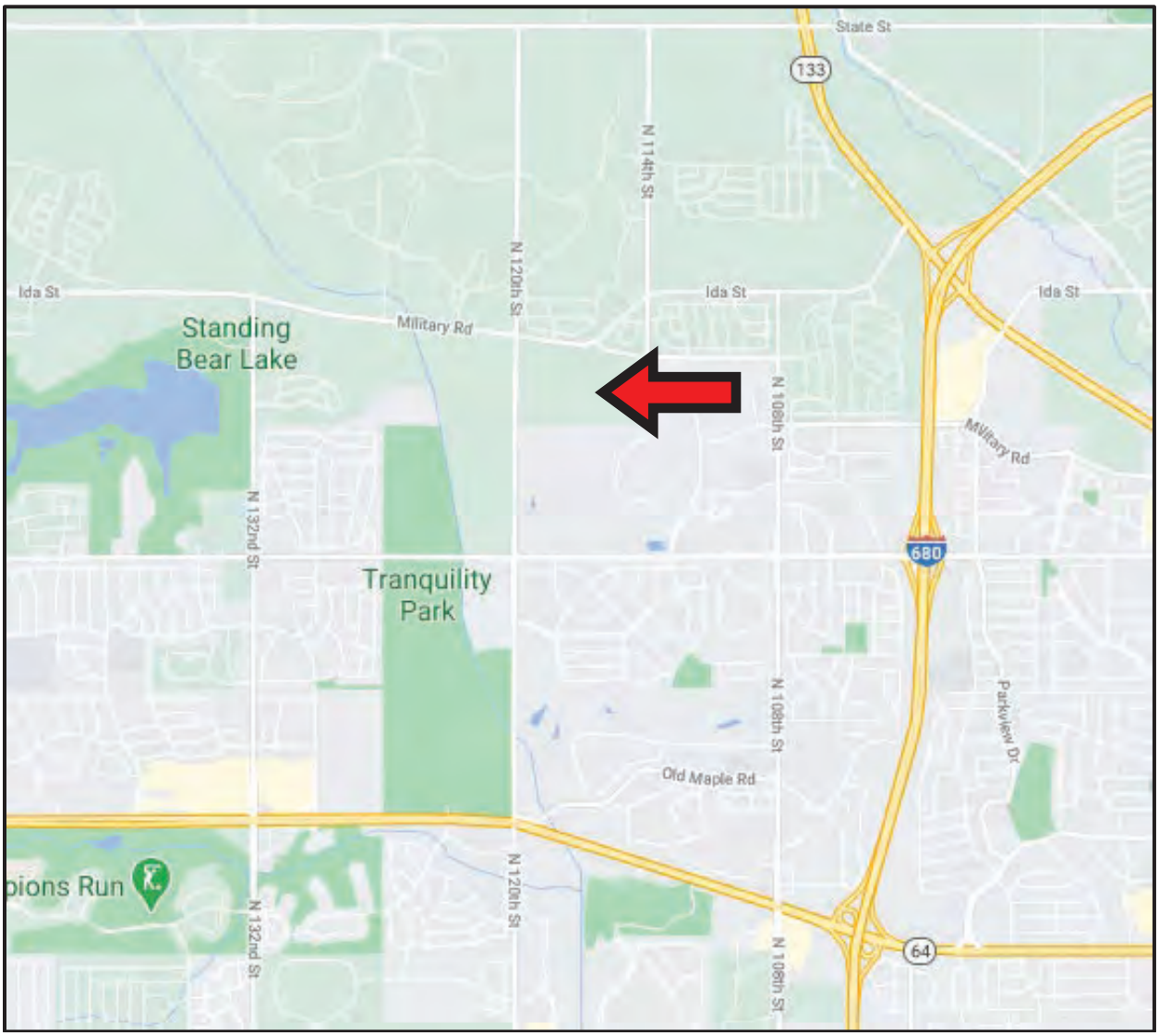
Project Location: State of Nebraska, County of Douglas, NW Omaha

Project Address: Military Rd Omaha, NE 68164

Approximate GPS: 41.315741, -96.094803

The Facility is located southeast of the intersection of Military Road and North 120th Street. Interstate 680 exit 5 (Fort Street) is the closest highway access point.

The Site location is indicated on the map below and a satellite view of the Site is shown in the aerial map that follows.





The Facility will be in a suburban area in northwest Omaha, on a primarily greenfield site. The Site is co-located on a Metropolitan Utilities District site. The Facility will consist of nine RICE generator sets installed inside an engine hall exhausting outdoors to emission reduction catalysts, exhaust silencers, and exhaust stacks.

Primary fuel for the engines will be pipeline quality natural gas, with backup fuel being ultra-low sulfur diesel. The engines will be capable of blending hydrogen into the natural gas in the future when hydrogen fuel becomes available.

Power from the Facility will be directed to a substation located on the site that also serves as a power delivery substation for the area.

The Facility is anticipated to be operated as a regulating and peaking power Facility, with the engines operating in a cyclic manner to support grid demands.

Refer to the preliminary site plan located in Appendix 10.

1.3 TURTLE CREEK SITE

Facility Name: Turtle Creek Station

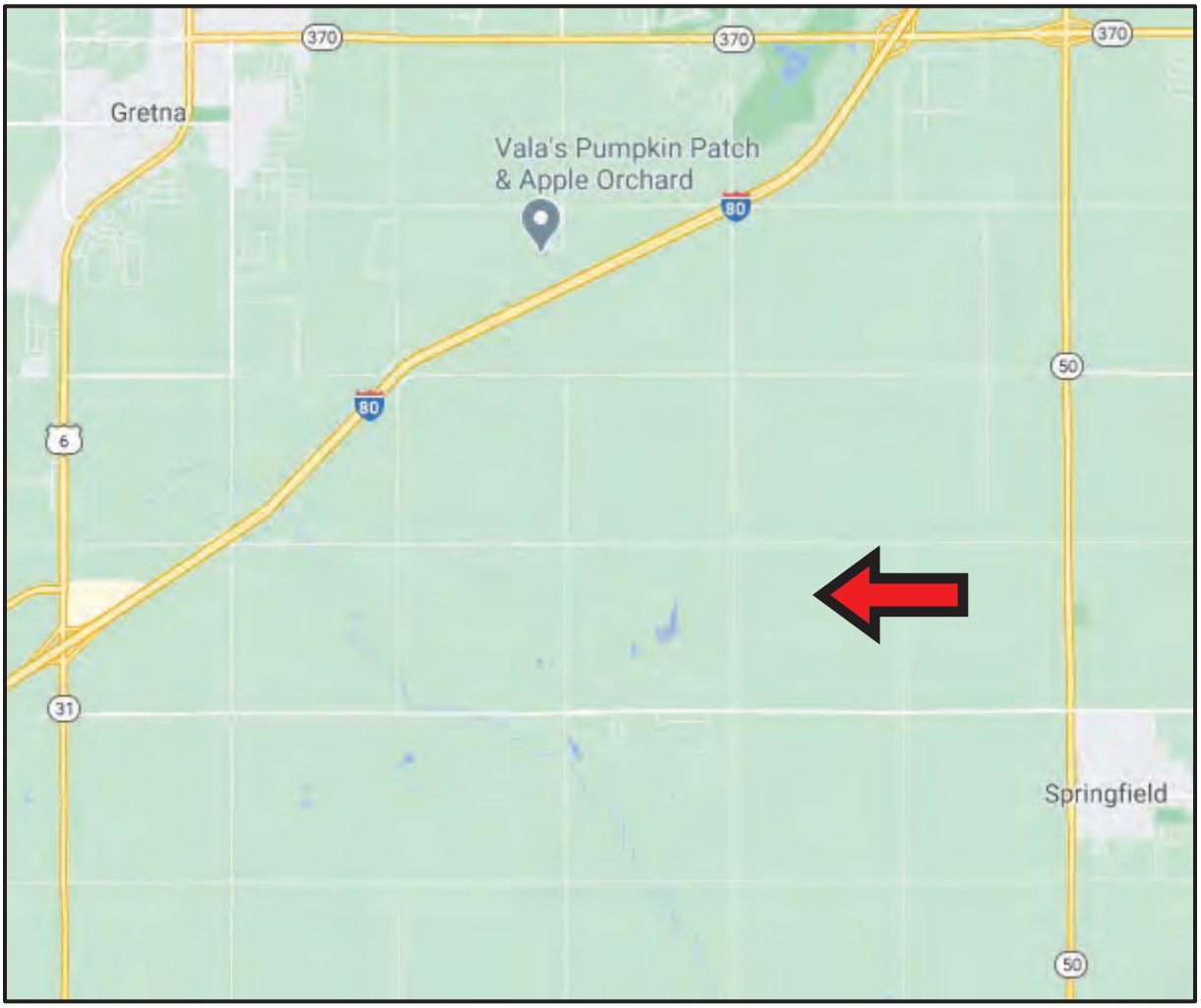
Project Location: State of Nebraska, County of Sarpy

Project Address: 14601 South 168th Street, Gretna, NE 68028

Approximate GPS: 41.095489, -96.170071

The Facility is located southeast of the intersection of Fairview Road and S 168th Street. Interstate 80 exit 432 (NE-31 or S216th Street) is a nearby Interstate highway access point.

The Site location is indicated on the map below and a satellite view of the Site is shown in the aerial map that follows.





The Facility is in a rural area approximately 15 miles southwest of downtown Omaha on agricultural land and adjacent to the Sarpy County landfill. The Facility will consist of two combustion turbine generator sets installed outdoors and exhausting to emission reduction modules.

Primary fuel for the CTG's will be pipeline quality natural gas, with backup fuel being ultra-low sulfur diesel. The CTG's should be capable of blending hydrogen into the natural gas in the future when hydrogen fuel becomes available.

Power from the Facility will be directed to a substation located on the site.

The Facility is anticipated to be operated as a regulating and peaking power Facility, with the CTG's operating in a cyclic manner to support grid demands.

Refer to the preliminary site plan located in Appendix 10.

EXHIBIT E

GUARANTEED COMPLETION DATES AND PROJECT SCHEDULES

GUARANTEED SUBSTANTIAL COMPLETION DATES

Standing Bear Lake Station Guaranteed Substantial Completion Date	May 1, 2023
Turtle Creek Station Guaranteed Substantial Completion Date	August 18, 2023

EXHIBIT
C

CHANGE ORDER NO. 1

Date: November 9, 2023

Project: Omaha Public Power District-Turtle Creek Station/Standing Bear Lake Station (the "Project")

Parties: Omaha Public Power District, a public corporation and political subdivision of the State of Nebraska ("OPPD" or "District") and Zachry Industrial, Inc. ("Contractor") (together, the "Parties").

Contract: Engineer, Procure, and Construct Contract for Omaha Public Power District Standing Bear Lake and Turtle Creek Generating Stations, Dated September 21, 2021 (OPPD Contract No. 263406) (the "EPC Contract").

This Change Order No. 1 ("Change Order") amends the EPC Contract and is entered into between OPPD and Contractor effective November 9, 2023 (the "Change Order Effective Date").

WHEREAS, the EPC Contract defines the terms "Contract Change Request (CCR)" and "Change Order" and those definitions shall apply to this Change Order;

WHEREAS all other capitalized terms used in this Change Order shall have the meaning set forth in the EPC Contract, unless otherwise stated herein;

WHEREAS, Contractor has submitted CCRs and supporting information, OPPD has considered the CCRs and supporting information, and OPPD issues this Change Order;

WHEREAS, for purposes of this Change Order, the Parties shall refer to the subject CCRs described herein and set forth on Exhibit "A" hereto as "Potential Change Notices" ("PCNs"); and

WHEREAS, the Parties entered into a Memorandum of Agreement on October 11, 2023, setting forth their agreement regarding certain PCNs ("MOA"); and

WHEREAS, contemporaneously with the execution of this Change Order, OPPD and Contractor have executed Amendment No. 1 to the EPC Contract, which, among other terms and consistent with the MOA, sets forth Revised Guaranteed Substantial Completion Dates for Standing Bear Lake Station ("SBLS") of August 8, 2024, and for Turtle Creek Station ("TCS") of August 30, 2024.

NOW THEREFORE, in consideration of the foregoing recitals (which are incorporated herein by this reference) and the covenants and agreements contained herein, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the parties further agree as follows:

1. **Defined Terms.** Unless otherwise defined herein, all capitalized terms used herein shall have the meanings ascribed thereto in the EPC Contract.

2. **Change Order and Amount.**

EXHIBIT D

Exhibit “A” sets forth the PCNs that are the subject of this Change Order. The Parties agree to the amounts set forth on Exhibit "A" as satisfaction for such PCNs and accept the cancellation of those PCNs described to be canceled. Payment for the PCNs identified with Invoice Month of November 2023 shall be paid Net 10 days from receipt of invoice. Payment for the PCNs identified with any other Invoice Month set forth on Exhibit "A" shall be paid in accordance with the EPC Contract. Withholding of retainage will be pursuant to the terms of the EPC Contract.

3. **ProlecGE Transformers**

As set forth in the MOA, OPPD agrees to accept the derated ProlecGE transformers for TCS. All other performance obligations relating to the GSU Transformers referenced in the EPC Contract shall remain in full force and effect. In exchange for OPPD’s acceptance of the derated transformers, Contractor will credit OPPD $3,902,000. The credit shall be applied against the amount invoiced by Contractor for PCNs identified with Invoice Month of November 2023.

4. **Siemens Commissioning Schedule.**

Siemens Energy (“Siemens”) has supplied Owner Furnished Equipment (“OFE”) to TCS under a separate contract with OPPD. Upon successful completion of commissioning at TCS, OPPD agrees to provide, and Contractor agrees to accept, the lump sum payment of $2,250,000, to cover an additional thirty-six (36) days in connection with Contractor’s Work for an expanded Siemens’ OFE commissioning schedule. Contractor shall remain responsible for commissioning of TCS and SBLS in accordance with the terms of the EPC Contract.

5. **Soil Compaction.**

As set forth in the MOA, based on Contractor's third-party geotechnical report, OPPD accepts any site erosion, settlement, foundation movements, and other impacts that occur after the two (2) year EPC Contract Warranty (beginning with Substantial Completion).

6. **Low Voltage Switch Gear at SBLS.**

As set forth in the MOA, all issues related to the Low Voltage Switchgear are the sole responsibility of Contractor.

7. **Change to Contract Price.**

The Contract Price is as detailed below:

The original Contract Price was: $366,207,836.00.

The Contract Price shall be increased by this Change Order in the amount of $64,185,282 for the accepted PCNs detailed on Exhibit “A.”

Additionally, the Contract Price shall be decreased in the amount of $3,902,000 to reflect the credit referenced in Section 3 above.

Additionally, the Contract Price shall be increased for the Siemens Commissioning Schedule work described in Section 4 of this Change Order in the amount of $2,250,000.

The adjusted Contract Price, including the price of this Change Order, is: $428,741,118.00.

8. **Effect of Change Order**.

Contractor agrees to perform the above-described Work in accordance with the above terms and in compliance with the Contract Documents. The adjustment in the Contract Price set out in this Change Order (and the adjustment in the Guaranteed Substantial Completion Dates made in Amendment No. 1) shall constitute the entire compensation and/or adjustment in the Contract Price and contract time due Contractor arising out of the changes for the Work covered by this Change Order. Contractor forever waives, relinquishes, releases, and discharges OPPD from any and all present or future claim of any kind for additional compensation or payment, whether known or unknown, or which may arise in the future, of or relating to Contractor's alleged "cumulative impact" claim initially set forth in its letter to OPPD dated May 12, 2023, whether such claim is described as a "cumulative impact" claim or by any other description or name, and whether such claim is asserted under the terms of the EPC Contract or of any other agreement or legal document, or pursuant to any statute or legal or equitable theory, doctrine, rule, or common law principle. No additions or deletions to this Change Order shall be allowed, except with written permission of the District.

9. **Miscellaneous.**

Except as specifically modified in this Change Order, the terms of the EPC Contract shall remain unchanged and in full force and effect. This Change Order may be executed in separate counterparts, and delivered via email, which shall be sufficient to bind the parties to the terms and conditions of this Change Order.

IN WITNESS WHEREOF, the Parties have caused this Change Order No. 1 to be executed by their duly authorized representatives as of the date set forth above.

OMAHA PUBLIC POWER DISTRICT

By: DocuSigned by: 80AC33D8E87A4D3...

Title: Contract Specialist

ZACHRY INDUSTRIAL, INC.

By: DocuSigned by: Ralph Biediger 4E061F33D33B4DA...

Title: President, Projects Group

CONFIDENTIAL SETTLEMENT COMMUNICATION
SUBJECT TO FRE 408 & ALL SIMILAR PROTECTIONS

AMENDMENT NO. 2 TO
ENGINEER, PROCURE, AND CONSTRUCT CONTRACT FOR OMAHA PUBLIC POWER DISTRICT STANDING BEAR LAKE AND TURTLE CREEK GENERATING STATIONS (CONTRACT NO. 263406)

This AMENDMENT NO. 2 to Contract No. 263406 ("**Amendment No. 2**") is entered into as of this 13 day of August ("**Effective Date**"), by and between Omaha Public Power District, a public corporation and political subdivision of the State of Nebraska ("**OPPD**"), and Zachry Industrial, Inc., a Texas corporation ("**Contractor**") (together with OPPD, the "**Parties**" or individually, a "**Party**").

WHEREAS, OPPD and Contractor are parties to that certain *Engineer, Procure, and Construct Contract for Omaha Public Power District Standing Bear Lake and Turtle Creek Generating Stations* (Contract No. 263406) dated 21 of September, 2021 (the "EPC Contract");

WHEREAS, pursuant to Article IV, Subsection (b) of the EPC Contract, OPPD withholds five percent (5%) of each Milestone Payment owed to Contractor as retainage and as of the Effective Date, OPPD is holding approximately [$20,220,446] in retainage (the "**Retainage**");

WHEREAS, Contractor and certain of its affiliates (collectively, the "**Debtors**") filed voluntary petitions for relief under chapter 11 of the United States Bankruptcy Code (the "**Bankruptcy Code**") in the United States Bankruptcy Court for the Southern District of Texas ("**Bankruptcy Court**") on May 21, 2024 (the "**Petition Date**"), which initiated the chapter 11 cases (the "**Chapter 11 Cases**") now jointly administered under lead case number 24-90377 (MI); and

WHEREAS, OPPD and Contractor desire to amend the EPC Contract as described herein.

NOW, THEREFORE, in consideration of the mutual covenants set forth below, the Parties agree as follows:

1. Defined Terms. Unless otherwise defined herein, all capitalized terms used herein shall have the meanings ascribed thereto in the EPC Contract.

2. Amendment of Article IV – Contract Price, Payment. Article IV, Subsection (b) of the EPC Contract is hereby deleted in its entirety and replaced in its entirety with the following:

(b) Milestone Payments. Contractor shall submit an invoice, on the tenth (10th) day of each month, showing milestones completed and payments due for those milestones in accordance with the Milestone Payment Schedule set forth in Exhibit G. After review and approval of the invoice by OPPD, milestone payments shall be made to the Contractor in the amount of 100% of approved invoice, without withholding of retainage. Such payment shall be made approximately fifteen (15) days from receipt of the invoice. Payment of such

EXHIBIT
E

monthly milestone payments by the District shall not be construed or deemed to be an acceptance of the Work covered thereby.

3. Amendment of Article IV – Contract Price, Payment. Article IV of the EPC Contract is hereby amended to add the following Section (i):

(i) Contractor warrants and agrees that it has the necessary work force and resources to complete the Work, including achieving the Guaranteed Substantial Completion Dates. In an effort to expedite completion of the Work, and provided that Contractor shall assume the EPC Contract (as amended) as specified in Section 10 hereof and recommend approval of this Amendment by the Bankruptcy Court of the Southern District of Texas, the District shall remit certain "Milestone Final Completion" payments to the Contractor. These Milestone Final Completion payments are contingent on the Contractor meeting the lesser of ninety days (90) from Substantial Completion or the dates for the respective Sites listed in subsections (a) and (b) below. Failure of Contractor to meet the scheduled dates below for each individual site will result in Contractor forfeiting the additional Two Million Dollar ($2,000,000.00) payment for the respective Site set forth in this Amendment No. 2. Subject to the terms of the EPC Contract, including this Amendment No. 2, the Milestone Final Completion payments shall be adjusted as follows:

On Final Completion, the Milestone Final Completion payment shall increase by Two Million Dollars ($2,000,000.00) per site from the allotted amount set forth in the EPC Contract:

(a) SBLS will be a payment of Three Million Dollars ($3,000,000.00) if the current schedule date of March 30, 2025 is met.

(b) TCS will be a payment of Three Million Dollars ($3,000,000.00) if the current schedule date of March 16, 2025 is met.

4. Amendment of Article IV – Contract Price, Payment. Article IV of the EPC Contract is hereby amended to add Section (j), as set forth below:

(j) Release of Retainage. The following procedures shall apply to the release of the Retainage:

(i) SurTec Information Systems, Inc. shall serve as Contractor's designated third-party administrator (the "**Agent**");
(ii) Contractor shall direct Agent to establish an escrow account (the "**OPPD Escrow Account**");
(iii) Upon execution of this Amendment No. 2, OPPD shall promptly deposit the entirety of the Retainage into the OPPD Escrow Account; and
(iv) The Agent shall directly pay Subcontractors, associated with the funds held in the OPPD Escrow Account; *provided that*, OPPD shall receive

contemporaneous notice of all payments made from the OPPD Escrow Account.

5. Amendment of Article XI – Liquidated Damages. Article XI Section (f) of Amendment No. 1 to the EPC Contract is hereby deleted in its entirety, such that Article XI, Section (f) now provides in its entirety, the following:

(f) Payments for Early Completion. Provided that Zachry has successfully completed commissioning requirements per the EPC Contract, as determined by OPPD, Zachry shall be entitled to receive the following payments, to be paid within fifteen (15) days of receipt of an invoice:

(1) For SBLS, $193,548.00 per day for each calendar day before the Guaranteed Substantial Completion Date that the Work is completed. There shall be an overall cap on this compensation of $5,999,988, reflecting up to 31 calendar days.

(2) For TCS, $352,941.00 per day for each calendar day before the Guaranteed Substantial Completion Date that the Work is completed. There shall be an overall cap on this compensation of $5,999,997, reflecting up to 17 calendar days.

6. Amendment of Article XI – Liquidated Damages. Article XI, Section (b) of Amendment No. 1 to the EPC Contract, is hereby deleted in its entirety, such that Article XI, Section (b) of the Agreement now provides, in its entirety, the following:

(b) On or before August 31, 2024, EPC Contractor, OFE Suppliers and OPPD shall meet and confer regarding the status of Acceptance Tests and progress toward meeting the Guaranteed Substantial Completion Date(s), and EPC Contractor and Suppliers shall commit in writing that the Work will be completed by the Guaranteed Substantial Completion Date(s). Failure to meet the Guaranteed Substantial Completion Date(s) shall be subject to the provisions of subsection (c)(1) below. Such provisions shall be the sole and exclusive remedy for any such failure.

7. Amendment of Article XI – Liquidated Damages. Article XI, Section (c), Subsection (1) (i) and (ii) of the EPC Contract is hereby deleted in its entirety, such that Article XI, Section (c), Subsection (1) (i) and (ii) of the EPC Contract now provides, in its entirety, the following:

(1) Delay in Completion of Work

(i) If the Contractor fails to complete the Work on or before the Guaranteed Substantial Completion Date, for SBLS, as a predetermined reasonable and sole and exclusive remedy for such delay, the Contractor shall be subject to liquidated damages as follows: For each calendar day beyond the Guaranteed

Substantial Completion Date for SBLS that the Work is not completed, $350,000 per calendar day through January 29, 2025, and $500,000 per calendar day until the Work is accepted as complete. There shall be an overall sub-cap on this liability equal to ten percent (10%) of the Contract Price. If Substantial Completion has not been achieved by February 28, 2025, then on March 1, 2025, Contractor shall pay the remainder of such maximum liquidated damages applicable to SBLS.

(ii) If the Contractor fails to complete the Work on or before the Guaranteed Substantial Completion Date, for TCS, as a predetermined reasonable and sole and exclusive remedy for such delay, the Contractor shall be subject to liquidated damages as follows: For each calendar day beyond the Guaranteed Substantial Completion Date for TCS that the Work is not completed, $250,000 per calendar day, through January 15, 2025, and $400,000 per calendar day until the Work is accepted as complete. There shall be an overall sub-cap on this liability equal to ten percent (10%) of the Contract Price. If Substantial Completion has not been achieved by February 14, 2025, then on February 15, 2025, Contractor shall pay the remainder of such maximum liquidated damages applicable to TCS.

8. Revised Schedule. The Guaranteed Substantial Completion Date for SBLS shall be December 30, 2024, and the Guaranteed Substantial Completion Date for the TCS will now be December 16, 2024.

9. Waiver. Upon execution of this Amendment No. 2 and approval of the Bankruptcy Court, all OPPD's current and future Owner Furnished Equipment (OFE) backcharges will be waived and dismissed and all of Contractor's current and future Potential Change Notices (PCN's) will be waived and dismissed.

10. Assumption. Contractor shall seek Court approval to assume the Agreement (as amended by this Amendment) pursuant to Section 365 of the Bankruptcy Code. The Parties agree that all requirements for assumption of this Agreement (as amended by this Amendment) under section 365(b)(1) of the Bankruptcy Code shall be satisfied upon the Parties' entry into this Amendment No. 2. Contractor acknowledges and agrees that it shall continue to perform all obligations under the EPC Contract (as amended by Amendment No. 1 and Amendment No. 2), including achieving Substantial Completion of the SBLS and the TCS as specified in Section 8 of this Amendment No. 2.

11. Bankruptcy Court Approval and Effectiveness. This Amendment No. 2 shall be effective only upon entry of an order by the Bankruptcy Court of the Southern District of Texas approving Contractor's assumption of the EPC Contract (as amended) pursuant to section 365 of the Bankruptcy Code. Upon entry of such order by the Bankruptcy Court of the Southern District of Texas, Sections 6 and 7 of this Amendment shall take effect retroactively to the date of execution of this Amendment.

12. Effect of Amendment. Except as provided in Amendment No. 1 and this Amendment No. 2, all other terms and conditions of the EPC Contract shall remain the same and in full force and effect.

13. Counterparts. This Amendment may be executed and delivered by facsimile or other electronic means and upon such delivery the facsimile or electronic signature will be deemed to have the same effect as if the original signature had been delivered to the other Party. This Amendment may be executed in one or more counterparts, all of which taken together shall constitute one and the same instrument.

[*Signature Page to Follow*]

IN WITNESS WHEREOF, the Parties have caused this Amendment to be executed by their duly authorized representatives as of the date set forth above.

OMAHA PUBLIC POWER DISTRICT

By: _____

Title: _____

Date: _____

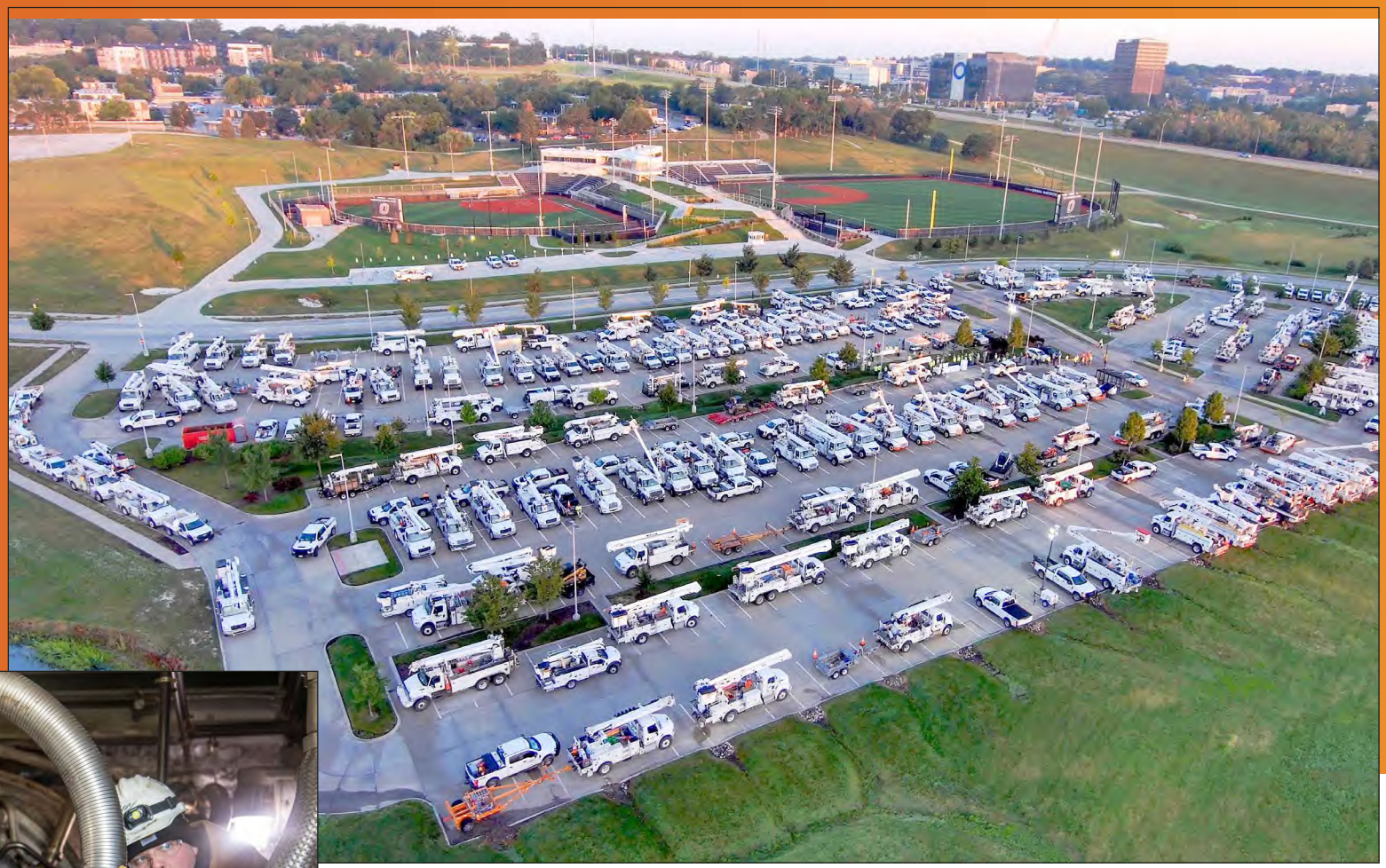
ZACHRY INDUSTRIAL, INC.

By: _____

Title: President, EPC

Date: 8/14/2024

2025 CORPORATE OPERATING PLAN





EXHIBIT

F

Omaha Public Power District

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MANAGEMENT LETTER

Management Letter



Every day in 2024, Omaha Public Power District (OPPD) worked tirelessly to overcome challenges and prepare for a bright future.

We diversified our portfolio with energy sources that will enhance our reliability during extreme weather, reduce our carbon output and help us meet fast-growing customer demand for electricity.

We're forging ahead with plans for advanced metering infrastructure (AMI) technology, which will help us assess and restore outages with greater speed and precision.

We also powered through major challenges this year, including extreme cold and low river levels in January that affected generation plants on the Missouri River, an April tornado that devastated Elkhorn and Bennington, major flooding near our Fort Calhoun Station site and a July 31 storm with hurricane-force winds that caused the biggest outage in OPPD history.

Above all, our public power mission kept us focused on reliability, affordability and environmental sustainability. Our locally elected Board of Directors continued to guide us with forward-looking directives to serve the community.

Our 2025 Corporate Operating Plan recommends a 6.3% rate increase, composed of a 4.9% average general rate increase and a 1.4% increase from the Fuel and Purchased Power Adjustment (FPPA) factor and replenishment of the Rate Stabilization Account (RSA). The general rate increase is driven by rising net power costs from increasing load and a growing capital portfolio, leading to additional debt issuances. The FPPA and RSA impact is driven by outages and storm restoration costs. FPPA is the mechanism OPPD uses to collect price fluctuations from year to year.

For context, OPPD's rates are still far lower, on average, than other utilities. Residential rates are 25.2% below the national average, according to the U.S. Energy Information Administration's final 2023 report, the most recent data available.

As the energy landscape changes, OPPD is working on multiple fronts to adapt and thrive – and our future is bright.



L. Javier Fernandez
President and Chief Executive Officer



STRATEGIC PLANNING AND ENTERPRISE RISK



Strategic Direction

To provide clear and transparent direction on behalf of OPPD's customer owners OPPD's publicly elected Board of Directors established fifteen strategic direction (SD) policies in 2015 to which OPPD is accountable. The policies guide OPPD's planning efforts to address current and future trends, mitigate risks, pursue strategic opportunities, and prioritize resources to efficiently and effectively provide energy services to our customer owners. The SD policies leverage industry benchmarks to drive performance as a top utility and provide the basis for a scorecard to which the organization manages its performance. The Board monitors OPPD's compliance with these policies and updates the policies, when determined appropriate, to clarify strategic direction.

Our Strategic Foundation (SD-1)

Mission: To provide affordable, reliable and environmentally sensitive energy services to our customers.

Vision: "Leading the Way We Power the Future"

In implementing this vision, OPPD shall adhere to these principles:

- Strengthen the public power advantage of affordable and reliable electricity;
- Exemplify fiscal, social and environmental responsibility to optimize value to our customer-owners;
- Proactively engage and communicate with our stakeholders;
- Act transparently and with accountability for the best interest of our customer-owners;
- Collaborate, when appropriate, with partners; and
- Leverage OPPD's leadership to achieve these goals

Core Values

- We have a PASSION to serve
- We HONOR our community
- We CARE about each other

Board Strategic Direction Policies & Strategic Goals

Policy	Measure	Definition	Strategic Goal
Rates (SD-2)	% Below Regional Retail Average	Retail rate target of North Central Regional average published rates on a system average basis.	10%
Access to Credit Markets (SD-3)	Debt Coverage Ratio	Revenues less expenses divided by total annual senior and subordinate lien debt interest and principal payments.	2.0
Reliability (SD-4)	SAIDI	System Average Interruption Duration Index	< 90 mins
	SAIFI	System Average interruption Frequency Index	< 0.9 incidents
	EFOR	Equivalent Forced Outage Rate	< or = 8.0%
Customer Satisfaction (SD-5)	Absolute Satisfaction Score	Customer satisfaction for similar-sized utilities in the region across residential and business customers.	Top quartile
Safety (SD-6)	DART	Days Away, Restricted or Transferred	< or = 0.50
	PVIR	Preventable Vehicle Incident Rate	< or = 4.00
Environmental Stewardship (SD-7)	% Net reduction in CO2e	Strive to achieve net zero carbon equivalent (CO2e) emissions by 2050 relative to OPPD's 2013 benchmark with the following interim targets, 2027-41-51% net reduction. Future interim targets to be informed by and determined following the completion of the 2026 integrated resource plan.	Achieve net zero CO2e by 2050
Employee Relations (SD-8)	Employee Engagement	Composite score of employee engagement	Top quartile

For a full listing of the 15 Strategic Directives, which includes Integrated System Planning (SD-9), Ethics (SD-10), Economic Development (SD-11), Information Management & Security (SD-12), Stakeholder Outreach & Engagement (SD-13), Retirement Plan Funding (SD-14), Enterprise Risk Management (SD-15), please access the following link to the OPPD Board Policy document https://www.oppd.com/media/317205/oppd-board-policy-binder.pdf

Powering the Future to 2050



At OPPD, we've imagined the future. Powering the Future to 2050 (PF2050) is a strategic vision to make OPPD cleaner, more sustainable, and more innovative than you can believe. While others have been wondering about what's next, we've been hard at work, nights and weekends, planning out what the future of power looks like and how to bring it to life. The vision is clear – **Perfect Power**, **Customer Freedom**, and a **Cleaner World** enabled through a **Digitally Driven**, **Purpose-Driven Culture**, and **Future-Ready Posture** mindset.

In November of 2019, the Board of Directors revised SD-7 (Environmental Stewardship) and established the goal to conduct all operations in a manner that strives for the goal of net-zero-carbon production by 2050. In consideration of this revision, other SD policies, and transformational changes within and outside the industry, the Executive Leadership Team (ELT) created PF2050, which provides a strategic vision for the organization through the year 2050. PF2050 outlines a transformational journey and was developed with the expressed intent to meet or exceed the fifteen SD policies. This vision will transform OPPD to a digital utility with two-way and multi-directional power and communication flows, build a proactive grid, give customer-owners multiple options, minimize environmental impact, and reduce carbon emissions. The future is coming, and we want to make sure it is illuminated.

Acknowledging the rapidly evolving and increasingly complex environment we operate in, OPPD adopted a future-ready posture mindset. This means we are taking a thoughtful approach to investing in both core work ('keeping the lights on today') and in the efforts to power our next generation. This deliberate and agile approach resulted in the establishment of the enterprise-level resourcing priorities. These enterprise priorities are aligned under PF2050 and influence the current year's budget. The process ensures OPPD's finite resources are being used to facilitate the right work to get us closer to our objectives of Perfect Power, Customer Freedom, and a Cleaner World by 2050.

The 2025-2030 enterprise priorities (listed in priority order below) were established to provide this life essential energy service to our customer-owners and employees. Their requirements and aspirational futures are woven into the very DNA of these priorities and are the underpinnings of everything we do.

1. Resource Adequacy
2. Technology Transformation
3. Next Generation Grid
4. Master Facilities Plan

Powering the Future to 2050

OPPD leveraged PF2050 and the enterprise priorities to guide planning, prioritization, and resourcing decisions for this Corporate Operating Plan. The vision to meet the growing demands of the service territory is becoming a reality as we transition from strategic planning to resourcing the execution in service of our customer-owner requirements in 2030 and beyond. We will continue to build upon our resource prioritization & capacity management framework and strategic STEER trends and risk scanning capabilities that will result in new and better ways to deliver affordable, reliable, and environmentally sensitive energy services to our customers. Additional information regarding PF2050 can be found on https://www.oppdcommunityconnect.com/pf2050.







Enterprise Risk Management (SD-15)

Fundamental to effective planning is an understanding of the District's enterprise level risks and the development and implementation of initiatives and mitigation plans to respond to those risks. The District's Enterprise Risk Management (ERM) program specifies risk management standards, management responsibilities, and controls to help ensure risk exposures are properly identified and managed within agreed upon risk tolerance levels. Specific risk mitigation plans and procedures are maintained and reviewed periodically to provide focused and consistent efforts to mitigate various risk exposures. An increased focus on emerging risks, such as disruptive technology, was launched in 2023. This process will continue to strengthen executive leadership's understanding of these risks to ensure an optimal future-ready posture for the organization. In support of its 2025 corporate planning efforts, OPPD leveraged risk assessments and mitigation plans to help prioritize resource allocation. The ELT will continue to expand this effort by incorporating those critical trends identified and associated with PF 2050.

Theme	OPPD's Risk Management Focus
Retail Revenues & Wholesale Revenues	Persistently pursue customer and economic development to achieve economies of scale and strengthen the affordability of our rates. Optimize wholesale revenues and purchases to further benefit our customer-owners.
Resource Adequacy and Reliability	Acquire and maintain a high availability and diverse generation portfolio to serve a significantly growing customer demand.
Environmental Sensitivity	Ensure the District is compliant with all environmental regulations, well-positioned to respond to new regulations, and able to minimize our environmental impact.
Fuel Costs	Effectively manage the District's fuel portfolio through numerous mitigation strategies to continue to ensure low cost and resilient generation.
AMI & Tech Transformation Execution	Deliver world-class execution of priority initiatives that will create a future-ready posture to deliver increased value to our customer-owners.
Cyber & Physical Security	Vigorously defend customer information and District assets from all potential cyber and physical security threats inherent with national critical infrastructure.
Infrastructure Investment	Optimally invest in transmission, distribution, substation, facility, and technology assets to ensure reliable and resilient energy services and supporting functions will meet the demands of our customer-owners.
Workplace Safety	Continue promoting safety as a top priority to ensure every employee and contractor goes home as healthy as they came into work.
Community Partnership	Honor and support the communities in which we operate and fulfill the promise of public power.



ASSUMPTIONS

Assumptions

2025 Proposed Rate Action

Effective January 1, 2025, OPPD's 2025 Corporate Operating Plan assumes an average total rate increase of 6.3% across all customer classes, composed of a 4.9% average general rate increase and a 1.4% increase from the FPPA factor and replenishment of the RSA. The general rate increase is largely driven by rising net power costs and a growing capital portfolio which leads to additional debt issuances. The FPPA and replenishment of the RSA is driven by outages and storm restoration costs.

General

2024 Projected

Revenues, operations and maintenance (O&M), capital and deferred expenditures reflect the 2024 actual values and forecast submitted through September 30, 2024.

Financing/Investing

Financing

Revenue bonds with net proceeds of $460.0 million are included in the 2025 budget. The proceeds of these bonds are expected to be used for capital expenditures.

Average Earnings Rates on Funds

The average earnings rate used for all funds (including special purpose) for 2025 is 3.6% which is a decrease of 0.5% from the prior year's rate of 4.1%.

Energy Sales/Revenues

Load Forecast

The plan assumes a 12.5% increase in retail energy sales (MWh) and a 2.1% increase in the number of customers in 2025, as compared to the 2024 budget.

Assumptions

Generation and Purchased Power

Outages have been scheduled for the following base-load units in 2025:

1. Nebraska City Station Unit Number 2
2. North Omaha Station Units 4 & 5

Additionally, there are several shorter outages scheduled for other units. The purchased power budget includes generation supplied from 1,272 megawatts of wind capability, 80 megawatts of hydropower from the Western Area Power Administration, as well as 86 megawatts of solar capability.

Department Operations and Maintenance Budget

Department and division level budgets were proposed, and these plans were reviewed with the ELT for alignment with the strategic and operational objectives before submitting them in the 2025 Corporate Operating Plan for Board final approval.

Capital Budget Expenditures

The capital portfolio prioritization and allocation process continues to improve capital planning. The process enables better alignment with the strategic directives and provides more transparency of capital spending through improved project review and approval processes. The size of the capital budget continues to grow as the District undergoes system expansion to provide reliable electric service to a growing community.

Total 2025 Budget

The total 2025 Budget is $2.3 billion.

BUDGET SUMMARY
(DOLLARS IN THOUSANDS)

Total Budget

	BUDGET 2024	BUDGET 2025	INCREASE / (DECREASE)	% CHANGE
Capital Expenditures*	$ 727,000	$ 788,000	$ 61,000	8.4
Non-Fuel Operations & Maintenance	528,335	582,729	54,394	10.3
Fuel and Purchased Power	492,691	567,138	74,447	15.1
Total Debt Service and Other Expenses	189,242	216,317	27,075	14.3
Decommissioning Expenditures**	112,918	102,596	(10,322)	(9.1)
Payments in Lieu of Taxes	45,599	53,532	7,933	17.4
Reserves	11,939	13,269	1,330	11.1
TOTAL BUDGET	**$ 2,107,724**	**$ 2,323,581**	**$ 215,857**	**10.2**

*Capital Expenditures are shown net of Contributions in Aid of Construction

**Decommissioning Expenditures represent expenditures related to Decommissioning activity, which differs from Decommissioning Funding ($10.7 million) which is an expense and is reflected on the income statement.

Budget Component Comparison

	BUDGET 2024	BUDGET 2025	CHANGE
Capital Expenditures*	34.5%	33.9%	(0.6)
Non-Fuel Operations & Maintenance	25.1%	25.1%	0.0
Fuel and Purchased Power	23.4%	24.4%	1.0
Total Debt Service and Other Expenses	9.0%	9.3%	0.3
Decommissioning Expenditures**	5.4%	4.4%	(1.0)
Payments in Lieu of Taxes	2.2%	2.3%	0.1
Reserves	0.6%	0.6%	0.0
TOTAL BUDGET	**100.0%**	**100.0%**	**-**

NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.

FINANCIAL STATEMENTS



Financial Statements

Income Statement

The District uses a 2.0 debt service coverage ratio as the basis of annual budgets, which is based on SD-3 Access to Credit Markets. It should be noted that OPPD does not set budgets or other forward-looking plans on the basis of net income. Net income for 2025 is budgeted to be $203.1 million, which is $41.7 million or 25.9% higher than the 2024 budget.

Major Factors Contributing to the Change in Budgeted Operating and Net Income:

Operating revenues are $1,671.2 million, which is $238.8 million or 16.7% higher than the 2024 budget. As the District anticipates load growth across all customer classes, retail revenues are expected to increase $208.7 million or 17.0% from the 2024 budget. The increase in operating revenue was also impacted by higher wholesale revenue of $25.6 million or 15.6%. The wholesale revenue increase is largely driven by higher congestion hedging revenue. The 2024 budget took a very conservative approach to congestion hedging revenues, leading to an increase in 2025 to more closely reflect actual performance.

Operations and maintenance expenses are $1,149.9 million, which is $128.8 million or 12.6% higher than the 2024 budget. Fuel and purchased power account for an increase of $74.4 million, or 15.1%, when compared to 2024 budget. Other O&M increases are driven by costs and headcount growth associated with the District's strategic priorities as well as additional investment in vegetation management.

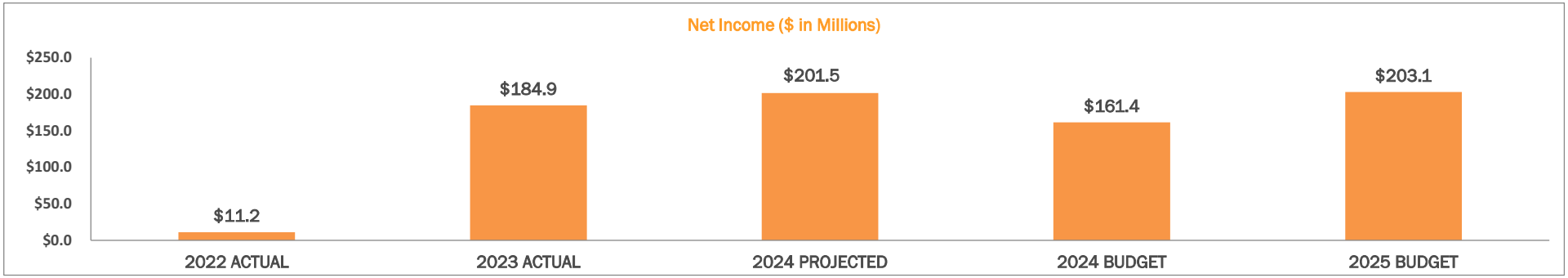
Other income is $88.8 million, which is $2.8 million or 3.2% higher than the 2024 budget amount due to largely offsetting impacts. Allowance for funds used during construction (AFUDC) is budgeted to increase by $13.1 million due to a growing capital portfolio, offset by decreased interest income of $11.9 million due to a lower earnings rate for funds on deposit.

Interest expense is $174.3 million in 2025 which is $22.6 million or 14.9% higher than the 2024 budget due to additional planned debt issuances required to execute a large capital portfolio.

OMAHA PUBLIC POWER DISTRICT
2025 CORPORATE OPERATING PLAN

INCOME STATEMENT
(DOLLARS IN THOUSANDS)

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET $ CHANGE	% CHANGE
OPERATING REVENUES	$ 1,400,784	$ 1,428,905	$ 1,516,446	$ 1,432,358	$ 84,088	$ 1,671,191	$ 238,833	16.7
OPERATING EXPENSES								
O&M EXPENSE	962,458	1,036,164	1,090,192	1,021,028	69,163	1,149,867	128,839	12.6
DEPRECIATION EXPENSE	150,074	124,980	143,871	138,448	5,423	183,433	44,985	32.5
PAYMENTS IN LIEU OF TAXES	40,462	42,498	45,827	45,599	228	53,532	7,934	17.4
DECOMMISSIONING EXPENSE	141,918	33,320	16,148	15,298	850	10,694	(4,604)	(30.1)
REGULATORY AMORTIZATION	14,835	13,600	-	-	-	-	-	-
TOTAL OPERATING EXPENSE	**$ 1,309,747**	**$ 1,250,562**	**$ 1,296,037**	**$ 1,220,373**	**$ 75,664**	**$ 1,397,526**	**$ 177,154**	**14.5**
OPERATING INCOME	**$ 91,037**	**$ 178,343**	**$ 220,409**	**$ 211,985**	**$ 8,423**	**$ 273,665**	**$ 61,680**	**29.1**
INTEREST INCOME	20,481	35,412	61,646	54,211	7,434	42,355	(11,856)	(21.9)
ALLOWANCE FOR FUNDS USED	16,427	33,079	39,504	26,332	13,173	39,481	13,149	49.9
PRODUCTS AND SERVICES - NET	2,868	2,092	1,772	2,484	(712)	3,952	1,469	59.1
MISC. NON OPERATING INCOME	25,917	4,718	1,008	3,000	(1,992)	3,000	-	-
MARK TO MARKET	(60,693)	38,747	11,204	-	11,204	-	-	-
TOTAL OTHER INCOME	**$ 5,000**	**$ 114,048**	**$ 115,134**	**$ 86,027**	**$ 29,108**	**$ 88,788**	**$ 2,761**	**3.2**
TOTAL INCOME LESS OPERATING EXPENSE	**$ 96,037**	**$ 292,391**	**$ 335,543**	**$ 298,012**	**$ 37,531**	**$ 362,453**	**$ 64,441**	**21.6**
INCOME DEDUCT. & INT. CHARGES								
INTEREST EXPENSE	97,739	120,168	147,203	151,720	(4,517)	174,319	22,599	14.9
OTHER INCOME DEDUCTIONS	1,787	3,091	3,917	1,205	2,712	1,205	-	-
AMORTIZATION	(14,694)	(15,767)	(17,030)	(16,271)	(759)	(16,157)	114	(0.7)
TOTAL INCOME DEDUCT. & INT. CHARGES	**$ 84,832**	**$ 107,491**	**$ 134,090**	**$ 136,654**	**$ (2,564)**	**$ 159,367**	**$ 22,713**	**16.6**
NET INCOME	**$ 11,205**	**$ 184,900**	**$ 201,453**	**$ 161,358**	**$ 40,095**	**$ 203,086**	**$ 41,728**	**25.9**



NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.

Financial Statements

Coverage Ratios

The Total Debt Service Coverage ratio, which is the key metric viewed by credit rating agencies, is budgeted to be 2.00 times in 2025, as directed by SD-3 Access to Credit Markets.

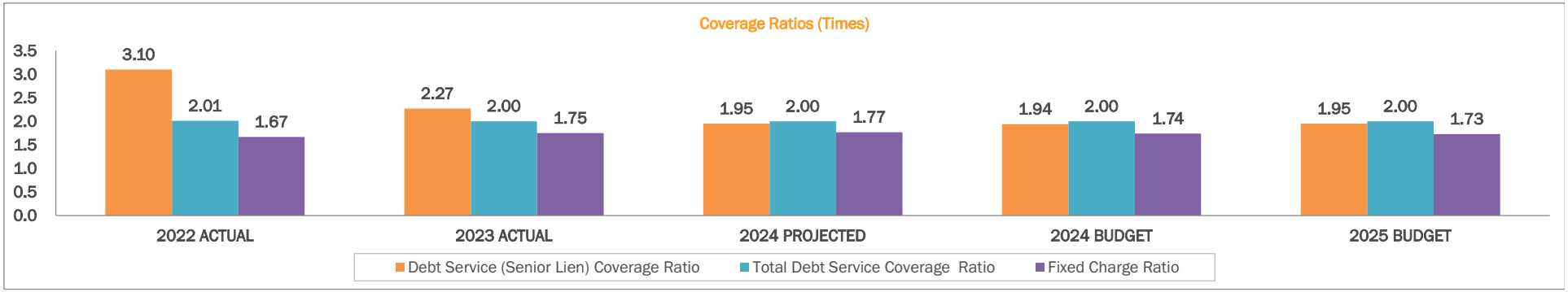
The Fixed Charge ratio is budgeted at 1.73 times in 2025, as compared to the budgeted 2024 value of 1.74 times.

The Senior Lien Debt Service Coverage ratio is budgeted to slightly increase to 1.95 compared to the 2024 metric of 1.94 times as increases in net receipts are offset by additional debt service requirements from additional borrowings. The additional debt issuances for senior lien revenue bonds are expected to be used to support a growing capital portfolio. Senior lien debt service requirements are expected to increase by $36.2 million or 19.6% from the 2024 budget amount.

OMAHA PUBLIC POWER DISTRICT
2025 CORPORATE OPERATING PLAN

COVERAGE RATIOS
(DOLLARS IN THOUSANDS)

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET $ CHANGE	25 BUDGET VS. 24 BUDGET % CHANGE
OPERATING REVENUES (EXCL. NC2)	$ 1,331,698	$ 1,354,221	$ 1,448,671	$ 1,368,804	$ 79,867	$ 1,600,681	$ 231,877	16.9
INTEREST INCOME - BONDS RESERVE ACCOUNT	1,357	3,229	5,354	3,491	1,863	4,383	892	25.6
PAYMENTS IN LIEU OF TAXES	(40,462)	(42,498)	(45,827)	(45,599)	(228)	(53,532)	(7,934)	17.4
O&M EXPENSE (EXCL. NC2 PARTICIPANT SHARE)	(930,054)	(1,000,481)	(1,055,662)	(966,215)	(89,447)	(1,118,677)	(152,462)	15.8
NET RECEIPTS	**$ 362,539**	**$ 314,471**	**$ 352,536**	**$ 360,481**	**$ (7,945)**	**$ 432,854**	**$ 72,373**	**20.1**
TOTAL DEBT SERVICE COVERAGE RATIO (DSC)	**2.01**	**2.00**	**2.00**	**2.00**	**-**	**2.00**	**$0**	**-**
DEBT SERVICE REQUIREMENTS (SENIOR LIEN)	$ 116,947	$ 138,251	$ 180,755	$ 185,183	$ (4,428)	$ 221,392	$36,209	19.6
DEBT SERVICE (SENIOR LIEN) COVERAGE RATIO	3.10	2.27	1.95	1.94		1.95		
FIXED CHARGE RATIO	1.67	1.75	1.77	1.74		1.73		



NOTE: Some columns may not foot exactly due to the method used for individual line item rounding. Total DSC as defined in OPPD's published Strategic Directive-3: Access to Credit Markets.

Financial Statements

Debt and Financing Data

Total senior lien revenue bonds outstanding at year-end 2025 are budgeted to equal $3,480 million. The 2025 budget anticipates the issuance of approximately $460.0 million of new senior lien revenue bonds and also includes senior lien revenue bond maturities and retirements of $52.5 million.

The 2025 budget does not anticipate the issuance of new subordinated bonds as all will mature or be retired during 2024.

Total commercial paper outstanding at year-end 2025 is budgeted to remain at the 2024 level of $250.0 million. The 2025 budget does anticipate the net impact of both an issuance and retirement of $100.0 million in new commercial paper.

Total separate system (Nebraska City Unit 2 (NC2)) revenue bonds outstanding at year-end 2025 are budgeted to equal $185.1 million. The 2025 budget does not anticipate the issuance of new NC2 revenue bonds but does have NC2 revenue bond maturities and retirements of $4.4 million.

The total average interest rate on existing debt is budgeted at 4.45% at the end of 2025 and the debt to capitalization ratio is budgeted to be 65.6% for 2025.

OMAHA PUBLIC POWER DISTRICT
2025 CORPORATE OPERATING PLAN

DEBT AND FINANCING DATA
(DOLLARS IN THOUSANDS)

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET $ CHANGE	% CHANGE
SENIOR LIEN REVENUE BONDS								
BALANCE - BEGINNING OF YEAR	$ 1,524,630	$ 1,935,320	$ 2,439,775	$ 2,439,775	$ -	$ 3,072,490	$ 632,715	25.9
NEW ISSUES	420,565	549,760	906,755	448,657	458,098	460,000	11,343	2.5
MATURITIES / RETIREMENTS	(9,875)	(45,305)	(274,040)	(45,895)	(228,145)	(52,535)	(6,640)	14.5
BALANCE - END OF YEAR	**$ 1,935,320**	**$ 2,439,775**	**$ 3,072,490**	**$ 2,842,537**	**$ 229,953**	**$ 3,479,955**	**$ 637,418**	**22.4**
AVERAGE INTEREST RATE (END OF YEAR)	3.85%	3.79%	4.13%	4.47%		4.44%		
SUBORDINATED								
BALANCE - BEGINNING OF YEAR	229,775	227,225	134,745	134,745	-	-	(134,745)	(100.0)
NEW ISSUES	-	-	-	-	-	-	-	-
MATURITIES / RETIREMENTS	(2,550)	(92,480)	(134,745)	(2,560)	(132,185)	-	2,560	(100.0)
BALANCE - END OF YEAR	**$ 227,225**	**$ 134,745**	**$ -**	**$ 132,185**	**$ (132,185)**	**$ -**	**$ (132,185)**	**(100.0)**
AVERAGE INTEREST RATE (END OF YEAR)	4.23%	6.54%		4.01%				
COMMERCIAL PAPER								
BALANCE - BEGINNING OF YEAR	325,000	250,000	250,000	250,000	-	250,000	-	-
NEW ISSUES	-	100,000	100,000	-	100,000	100,000	100,000	-
MATURITIES / RETIREMENTS	(75,000)	(100,000)	(100,000)	-	(100,000)	(100,000)	(100,000)	-
BALANCE - END OF YEAR	**$ 250,000**	**$ 250,000**	**$ 250,000**	**$ 250,000**	**$ -**	**$ 250,000**	**$ -**	**-**
AVERAGE INTEREST RATE (END OF YEAR)	1.50%	3.72%	4.00%	4.00%		4.27%		
SEPARATE SYSTEM REVENUE BONDS (NC2)								
BALANCE - BEGINNING OF YEAR	201,495	197,680	193,680	193,680	-	189,480	(4,200)	(2.2)
NEW ISSUES	-	-	-	-	-	-	-	-
MATURITIES / RETIREMENTS	(3,815)	(4,000)	(4,200)	(4,200)	-	(4,415)	(215)	5.1
BALANCE - END OF YEAR	**$ 197,680**	**$ 193,680**	**$ 189,480**	**$ 189,480**	**$ -**	**$ 185,065**	**$ (4,415)**	**(2.3)**
AVERAGE INTEREST RATE (END OF YEAR)	4.95%	4.95%	4.95%	4.95%		4.95%		
TOTAL AVERAGE INTEREST RATE (END OF YEAR)	**3.74%**	**3.98%**	**4.32%**	**4.44%**		**4.45%**		
TOTAL INTEREST EXPENSE (ON DEBT)	**$ 84,832**	**$ 107,491**	**$ 134,090**	**$ 136,654**	**$ (2,564)**	**$ 159,367**	**$ 25,277**	**18.9**
DEBT TO CAPITALIZATION RATIO	**64.00%**	**64.00%**	**65.60%**	**66.00%**		**65.60%**		

NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.

Financial Statements

Cash Flow Analysis

2025 Budget Compared to 2024 Budget

Cash Receipts

2025 cash receipts are budgeted to increase by $221.5 million to $1,714.3 million, a 14.8% change. This increase is primarily due to increased retail revenue from projected load growth and the general rate increase to customers.

Cash Disbursements

2025 cash disbursements are budgeted to increase by $221.5 million to $2,251.4 million, a 10.9% shift. Increases in cash disbursements relate to capital expenditures from a growing capital portfolio that also impacts increased debt service to support the capital portfolio. In addition, purchased power is expected to increase by $66.6 million due to higher purchase volumes to support customer load growth.

The budgeted values of cash receipts and disbursements result in a year-end cash balance of $688.3 million in 2025, a 30.1% or $159.4 million increase over 2024 budget.

OMAHA PUBLIC POWER DISTRICT
2025 CORPORATE OPERATING PLAN

CASH FLOW ANALYSIS
(DOLLARS IN THOUSANDS)

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET $ CHANGE	% CHANGE
CASH BEGINNING OF PERIOD	$ 636,681	$ 667,880	$ 693,066	$ 642,041	$ 51,025	$ 765,405	$ 123,364	19.2
RECEIPTS								
RETAIL REVENUES	1,126,285	1,109,853	1,266,898	1,222,054	44,844	1,423,890	201,836	16.5
WHOLESALE REVENUES (INCL. NC2)	248,490	239,797	229,419	168,881	60,538	194,677	25,796	15.3
INTEREST INCOME	50,004	53,081	59,235	57,211	2,024	45,034	(12,177)	(21.3)
OTHER ELECTRIC REVENUES	42,940	46,205	46,437	42,234	4,203	46,776	4,542	10.8
PRODUCTS & SERVICES	2,086	2,978	2,696	2,484	212	3,953	1,469	59.1
USE OF RESERVE ACCOUNTS	-	-	13,269	-	13,269	-	-	-
TOTAL RECEIPTS	**$ 1,469,805**	**$ 1,451,914**	**$ 1,617,954**	**$ 1,492,864**	**$ 125,090**	**$ 1,714,329**	**$ 221,465**	**14.8**
DISBURSEMENTS								
CAPITAL EXPENDITURES	551,032	574,608	762,355	727,000	35,355	788,000	61,000	8.4
O&M EXPENSE (W/O FUEL & PURCHASED POWER)	409,119	497,369	523,309	540,396	(17,087)	581,882	41,486	7.7
PURCHASED POWER	357,276	337,969	406,935	310,416	96,519	377,052	66,636	21.5
DEBT SERVICE	146,457	272,569	209,453	215,568	(6,115)	244,632	29,064	13.5
FUEL	188,414	157,894	147,135	178,358	(31,223)	187,841	9,483	5.3
PAYMENTS IN LIEU OF TAXES	38,605	40,494	42,281	42,882	(601)	48,044	5,162	12.0
CONTRIBUTIONS TO RESERVE ACCOUNTS	-	-	-	-	-	13,269	13,269	-
DECOMMISSIONING EXPENSE	141,918	33,320	16,303	15,298	1,005	10,694	(4,604)	(30.1)
CHANGES IN OTHER NET ASSETS	(17,420)	(36,663)	40	-	40	-	-	-
TOTAL DISBURSEMENTS	**$ 1,815,401**	**$ 1,877,560**	**$ 2,107,810**	**$ 2,029,918**	**$ 77,892**	**$ 2,251,415**	**$ 221,497**	**10.9**
NET OPERATING CASH FLOW	**$ (345,596)**	**$ (425,646)**	**$ (489,856)**	**$ (537,054)**	**$ 47,198**	**$ (537,086)**	**$ (32)**	**0.0**
FINANCING	474,385	477,870	968,651	448,657	519,994	483,000	34,343	7.7
FINANCING COST / RESERVE AMOUNT	(22,590)	(27,038)	(46,126)	(24,676)	(21,450)	(23,000)	1,676	(6.8)
COMMERCIAL PAPER - NET	(75,000)	-	-	-	-	-	-	-
OTHER	-	-	(360,330)	-	(360,330)	-	-	-
TOTAL FINANCING	**$ 376,795**	**$ 450,832**	**$ 562,195**	**$ 423,981**	**$ 138,214**	**$ 460,000**	**$ 36,019**	**8.5**
TOTAL CHANGE IN CASH	31,199	25,186	72,339	(113,073)	185,412	(77,086)	35,987	(31.8)
CASH END OF PERIOD	**$667,880**	**$693,066**	**$765,405**	**$528,968**	**$236,437**	**$688,319**	**$159,351**	**30.1**
DECOMMISSIONING FUND	**$534,901**	**$479,964**	**$406,731**	**$346,768**	**$59,963**	**$288,684**	**($58,084)**	**(16.8)**

NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.


ENERGY SALES

Energy Sales

Electric Energy Sales & Electric Customers

Total electric energy sales are budgeted to be 18,878,664 MWh, which is 8.5% or 1,479,981 MWh more than the 2024 budget. Retail energy sales are budgeted to be 15,355,048 MWh, or 12.5%, greater when compared to 2024 budget. This increase is driven by load growth across all customer classes. Wholesale energy sales (including NC2 participation sales) are budgeted to decrease by 226,624 MWh or 6.0% from 2024 budget as volumes are expected to decrease due to load growth consuming owned generation and leaving less energy available to sell into the marketplace.

In 2025, the average number of retail customers is budgeted to increase by 8,762, a 2.1% increase from 2024 budget.

OMAHA PUBLIC POWER DISTRICT
2025 CORPORATE OPERATING PLAN

ELECTRIC ENERGY SALES AND CUSTOMERS

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET. MWh CHANGE	% CHANGE
ELECTRIC ENERGY SALES (MWh)								
RESIDENTIAL	3,937,046	3,947,870	3,857,951	3,995,295	(137,344)	4,044,941	49,646	1.2
COMMERCIAL	3,763,330	3,796,608	3,800,810	3,891,422	(90,613)	3,927,174	35,752	0.9
INDUSTRIAL	4,293,784	4,683,632	5,812,465	5,703,474	108,990	7,318,775	1,615,301	28.3
UNBILLED SALES	111,815	(56,155)	83,552	58,252	25,301	64,158	5,906	10.1
RETAIL ENERGY SALES	**12,105,976**	**12,371,955**	**13,554,778**	**13,648,443**	**(93,666)**	**15,355,048**	**1,706,604**	**12.5**
NC2 PARTICIPANT	1,867,157	1,355,808	2,168,480	2,096,963	71,517	1,894,840	(202,123)	(9.6)
OTHER	2,543,536	1,969,829	1,397,202	1,653,278	(256,076)	1,628,777	(24,501)	(1.5)
WHOLESALE ENERGY SALES	**4,410,693**	**3,325,638**	**3,565,682**	**3,750,240**	**(184,559)**	**3,523,617**	**(226,624)**	**(6.0)**
TOTAL MWh SALES	**16,516,668**	**15,697,593**	**17,120,459**	**17,398,684**	**(278,224)**	**18,878,664**	**1,479,981**	**8.5**
ELECTRIC CUSTOMERS (12 MONTH AVG.)								
RESIDENTIAL	351,712	357,528	363,042	361,464	1,578	369,548	8,084	2.2
COMMERCIAL	49,550	49,782	50,320	49,987	333	50,665	678	1.4
INDUSTRIAL	135	133	135	149	(14)	149	-	-
TOTAL RETAIL CUSTOMERS	**401,397**	**407,443**	**413,497**	**411,600**	**1,897**	**420,362**	**8,762**	**2.1**
kWh / CUSTOMER								
RESIDENTIAL	11,194	11,042	10,627	11,053	(426)	10,946	(107)	(1.0)
COMMERCIAL	75,950	76,265	75,533	77,849	(2,316)	77,513	(336)	(0.4)
INDUSTRIAL	31,805,809	35,215,275	43,055,293	38,278,351	4,776,942	49,119,296	10,840,944	28.3
AVERAGE kWh / CUSTOMER	**29,881**	**30,503**	**32,579**	**33,018**	**(439)**	**36,376**	**3,358**	**10.2**

NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.

Energy Sales

Operating Revenues

Total electric operating revenues for 2025 are budgeted to be $1,671.2 million, which is $238.8 million or 16.7% above the 2024 budgeted operating revenues. Retail revenues are $208.7 million or 17.0% greater than 2024 budget due to load growth across all customer classes. Wholesale revenues are $25.6 million or 15.6% higher when compared to the 2024 budget primarily due to increased congestion hedging revenue.

OPERATING REVENUES
(DOLLARS IN THOUSANDS)

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET $ CHANGE	% CHANGE
ELECTRIC OPERATING REVENUES								
RESIDENTIAL	$ 460,848	$ 472,633	$ 479,045	$ 490,025	$ (10,980)	$ 539,712	$ 49,687	10.1
COMMERCIAL	336,360	350,956	371,319	378,580	(7,261)	402,565	23,985	6.3
INDUSTRIAL	291,343	317,828	378,704	363,789	14,915	504,432	140,642	38.7
UNBILLED REVENUES/ADJUSTMENTS	10,556	(2,354)	4,267	5,185	(918)	5,677	492	9.5
FPPA RECEIVABLE AMORTIZATION	7,400	(7,400)	4,766	-	4,766	(4,766)	(4,766)	-
USE OF (CONTRIBUTION TO) RESERVE	(6,000)	7,000	13,269	(11,939)	25,208	(13,269)	(1,330)	11.1
TOTAL RETAIL SALES	**$ 1,100,507**	**$ 1,138,663**	**$ 1,251,370**	**$ 1,225,640**	**$ 25,730**	**$ 1,434,351**	**$ 208,711**	**17.0**
NC2 PARTICIPANTS	69,086	74,684	67,775	63,554	4,221	70,511	6,956	10.9
OTHER	187,392	168,896	150,753	100,930	49,823	119,554	18,624	18.5
TOTAL WHOLESALE REVENUES	**$ 256,478**	**$ 243,580**	**$ 218,528**	**$ 164,484**	**$ 54,044**	**$ 190,065**	**$ 25,580**	**15.6**
TOTAL SALES OF ELECTRIC ENERGY	**$ 1,356,985**	**$ 1,382,243**	**$ 1,469,899**	**$ 1,390,125**	**$ 79,774**	**$ 1,624,416**	**$ 234,291**	**16.9**
OTHER ELECTRIC REVENUES	43,799	46,662	46,547	42,233	4,314	46,776	4,542	10.8
TOTAL ELECTRIC OPERATING REVENUES	**$1,400,784**	**$1,428,905**	**$1,516,446**	**$1,432,358**	**$84,088**	**$1,671,191**	**$238,833**	**16.7**

NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.

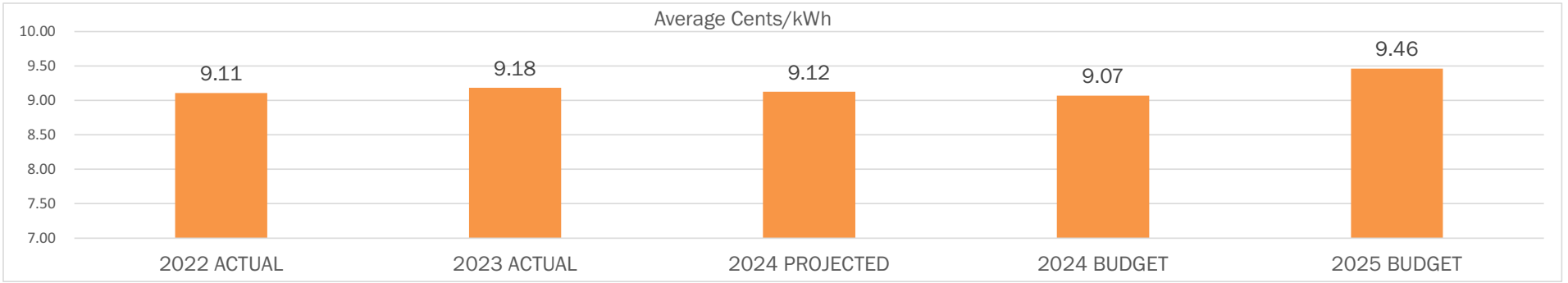
Energy Sales

Average Cents/kWh

The 2025 average price per kWh for retail customers is budgeted to be 9.46 cents. This is 0.39 cents, or a 4.3% increase, from the 2024 budget. A Cost-of-Service Study was performed to determine the cost of providing electric service to each rate class. The study was used as a baseline to determine the appropriate rate increase for each class. Individual customer impacts will vary based on their specific rate class and usage patterns.

AVERAGE CENTS/kWh

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET $ CHANGE	% CHANGE
RESIDENTIAL	11.73	11.97	12.42	12.27	0.15	13.34	1.07	8.7
COMMERCIAL	8.95	9.24	9.77	9.73	0.04	10.25	0.52	5.4
INDUSTRIAL	6.88	6.79	6.52	6.38	0.14	6.89	0.51	8.0
RETAIL AVERAGE *	**9.11**	**9.18**	**9.12**	**9.07**	**0.06**	**9.46**	**0.39**	**4.3**



NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.
* Average rates are from the revenue recognized on the Income Statement and do not incorporate accrued unbilled. These rates differ from customer billed rates and are calculated for benchmarking and illustrative purposes only.



NET SYSTEM REQUIREMENTS

Net System Requirements

Net system requirements (total retail sales as shown on the next page) for 2025 are budgeted to be 16,096,875 MWh, an increase of 1,731,308 MWh or 12.1% from the 2024 budget. The major components of net system requirements are below by sales and supply components.

Total sales are budgeted to increase 1,479,981 MWh or 8.5% from the 2024 budget, an increase largely driven by retail sales with an increase of 1,706,605 or 12.5% when compared to the 2024 budget.

For supply components, firm/participation purchases are the largest change with a budgeted increase of 1,143,962 MWh or 27.5% from the 2024 budget due to Platteview Solar and Milligan Wind being in service for the entirety of 2025.

Net System Requirements
Sales and Supply Components (MWh)

	BUDGET 2024	BUDGET 2025	INCREASE / (DECREASE)	% CHANGE
Sales Components				
Retail Sales	13,648,443	15,355,048	1,706,604	12.5
NC2 Participation Sales	2,096,963	1,894,840	(202,123)	(9.6)
Wholesale Energy Sales	1,653,278	1,628,777	(24,501)	(1.5)
Total	**17,398,684**	**18,878,664**	**1,479,981**	**8.5**
Supply Components				
Generation	10,147,180	10,252,594	105,414	1.0
Purchased Power Agreements	4,158,744	5,302,706	1,143,962	27.5
Wholesale Purchases	3,809,884	4,065,192	255,308	6.7
Lost or Unaccounted For	(717,124)	(741,828)	(24,703)	3.4
Total	**17,398,684**	**18,878,664**	**1,479,981**	**8.5**

NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.

OMAHA PUBLIC POWER DISTRICT
2025 CORPORATE OPERATING PLAN

NET SYSTEM REQUIREMENTS

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET MWh CHANGE	% CHANGE
GENERATION (MWh)								
GENERATION	**9,335,878**	**7,959,596**	**7,595,771**	**10,147,180**	**(2,551,408)**	**10,252,594**	**105,414**	**1.0**
FIRM/PARTICIPATION PURCHASES	4,473,672	3,514,769	4,484,291	4,158,744	325,547	5,302,706	1,143,962	27.5
WHOLESALE PURCHASES	3,198,414	4,655,118	5,544,605	3,809,884	1,734,721	4,065,192	255,308	6.7
TOTAL PURCHASES	**7,672,086**	**8,169,888**	**10,028,896**	**7,968,628**	**2,060,268**	**9,367,898**	**1,399,270**	**17.6**
TOTAL INPUT	**17,007,963**	**16,129,483**	**17,624,668**	**18,115,808**	**(491,140)**	**19,620,492**	**1,504,684**	**8.3**
WHOLESALE ENERGY SALES								
NC2 PARTICIPANT	1,867,157	1,355,808	2,168,480	2,096,963	71,517	1,894,840	(202,123)	(9.6)
OTHER	2,543,536	1,969,829	1,397,202	1,653,278	(256,076)	1,628,777	(24,501)	(1.5)
TOTAL WHOLESALE ENERGY SALES	**4,410,693**	**3,325,638**	**3,565,682**	**3,750,240**	**(184,559)**	**3,523,617**	**(226,624)**	**(6.0)**
NET SYSTEM REQUIREMENTS	**12,597,271**	**12,803,845**	**14,058,986**	**14,365,568**	**(306,582)**	**16,096,875**	**1,731,308**	**12.1**
TOTAL RETAIL SALES	12,105,976	12,371,955	13,554,778	13,648,443	(93,666)	15,355,048	1,706,604	12.5
ENERGY LOST OR UNACCOUNTED FOR	491,295	431,890	504,208	717,124	(212,916)	741,828	24,703	3.4
TOTAL RETAIL SALES	**12,597,271**	**12,803,845**	**14,058,986**	**14,365,568**	**(306,582)**	**16,096,875**	**1,731,308**	**12.1**

PEAK LOAD (MW)								
PEAK LOAD EXCLUDING DEMAND RESPONSE	2,680	2,928	2,959	3,009	(50)	3,164	155	5.2
DEMAND RESPONSE*	126	129	140	140	(0)	128	(12)	(8.6)
PEAK LOAD INCLUDING DEMAND RESPONSE	2,554	2,799	2,819	2,869	(50)	3,036	167	5.8
LOAD FACTOR (%) - REFLECTS DEMAND RESPONSE	56.3	52.2	56.9	57.2	(0.2)	60.5	3.4	5.9

NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.

* Does not include voluntary demand response

OPERATIONS AND MAINTENANCE EXPENSE



Operations and Maintenance Expense

The District's 2025 total budgeted O&M expense is $1,149.9 million, which is $128.8 million or 12.6% higher than the 2024 budget.

2025 Budget Compared to 2024 Budget

Purchased power, including wind purchases, represents 33.0% of total O&M expense and is budgeted at $379.7 million. This represents an increase of $67.2 million or 21.5% above the 2024 budget amount. The increase from the 2024 budget is primarily due to higher purchase volumes to serve anticipated customer load growth. As load growth outpaces owned generation, purchased power volumes are expected to increase.

Fuel expense is budgeted at $187.4 million, an increase of $7.3 million or 4.0% more than the 2024 budgeted amount primarily due to a full year of generation from Standing Bear Lake and Turtle Creek stations.

Transmission and distribution expense is budgeted at $192.7 million, which is $26.2 million or 15.7% more than the 2024 budgeted amount. The increase over the budget amount is attributable to additional external services, including tree trimming and cable locating, as well as increased headcount supporting growth at the utility.

Administrative and general expense is budgeted at $178.9 million. This category reflects an increase of $12.0 million or 7.2% more than the 2024 budget. The increase in 2025 is primarily related to rising costs associated with salary and benefits driven by both higher rates and an increase in the number of covered employees.

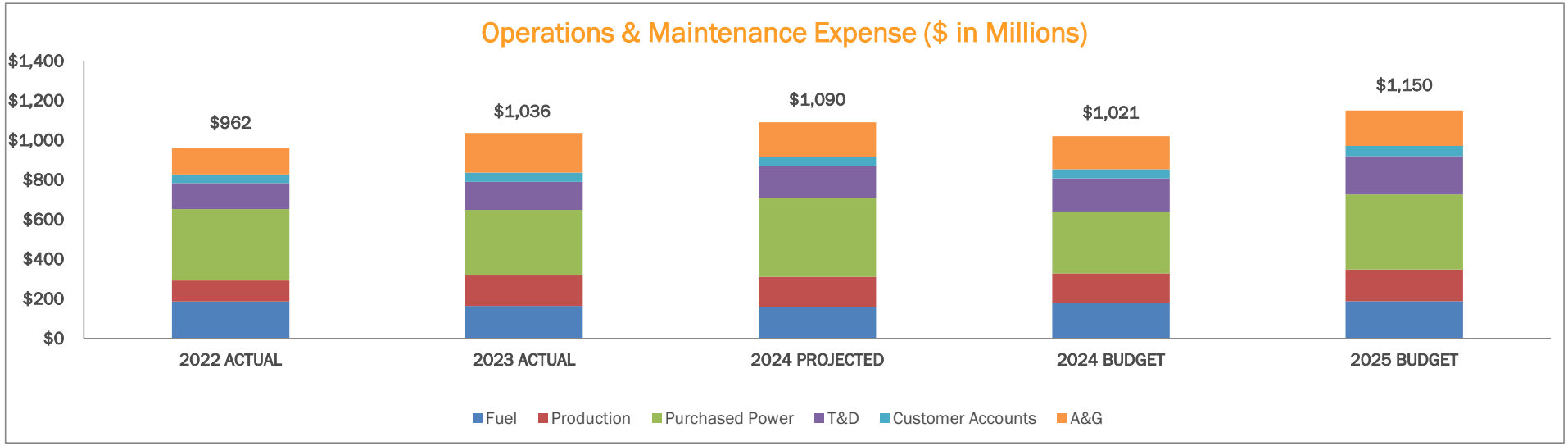
Production expense is budgeted to be $159.7 million, which is $12.0 million or 8.1% above the 2024 budgeted amount and is also impacted by a full year of operation at two new generating facilities, Standing Bear Lake and Turtle Creek as well as headcount growth.

Decommissioning expense represents the annual funding of the decommissioning liability. Decommissioning funding for 2025 is budgeted to be $10.7 million, which is $4.6 million or 30.1% less than the 2024 budget. Contributions to decommissioning represent investment earnings on balances in the decommissioning trust.

OMAHA PUBLIC POWER DISTRICT
2025 CORPORATE OPERATING PLAN

OPERATIONS AND MAINTENANCE EXPENSE
(DOLLARS IN THOUSANDS)

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET $ CHANGE	% CHANGE
PURCHASED POWER	$ 360,420	$ 332,382	$ 397,566	$ 312,527	$ 85,039	$ 379,716	$ 67,189	21.5
FUEL	186,359	164,240	157,857	180,164	(22,307)	187,422	7,258	4.0
SUBTOTAL	**546,779**	**496,622**	**555,423**	**492,691**	**62,732**	**567,138**	**74,447**	**15.1**
TRANSMISSION AND DISTRIBUTION	130,856	141,390	160,558	166,553	(5,995)	192,708	26,155	15.7
ADMINISTRATIVE AND GENERAL	135,402	199,820	173,038	166,938	6,100	178,926	11,988	7.2
PRODUCTION	105,534	152,812	152,976	147,748	5,228	159,699	11,951	8.1
CUSTOMER	43,887	45,520	48,196	47,096	1,100	51,396	4,300	9.1
TOTAL O&M EXPENSE	**$ 962,458**	**$ 1,036,164**	**$ 1,090,192**	**$ 1,021,028**	**$ 69,166**	**$ 1,149,867**	**$ 128,841**	**12.6**
DECOMMISSIONING EXPENSE	**$ 141,918**	**$ 33,320**	**$ 16,148**	**$ 15,298**	**$ 850**	**$ 10,694**	**$ (4,604)**	**(30.1)**



NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.



CAPITAL EXPENDITURE PLAN

Capital Expenditure Plan

Capital Expenditures

The 2025 capital budget was derived by breaking investments into three categories, sustain, enterprise priority and expand. This categorization ensures the District invests at appropriate levels to maintain existing assets but also invests in the continuing expansion of the utility.

Sustain - capital projects aimed at maintaining and improving existing assets

Expand - new assets, increasing the District's asset base

Enterprise Priority - projects directly related to Resource Adequacy, Technology Transformation, Next Generation Grid and the Master Facilities Plan

Capital expenditures represent 33.9% of the total 2025 budget. Capital expenditures are budgeted at $788.0 million, which is $61.0 million or 8.4% more than the 2024 budget.

The year over year growth is primarily related to investments in District expansion and enterprise priorities. Enterprise priority projects are budgeted at $474.1 million, which is a $70.6 million increase over the 2024 budget of $403.5 million, primarily related to investments in new generation. Expand, which includes projects related to load growth and economic development, are budgeted at $120.7 million, an increase of $15.4 million from the 2024 budget. Partially offsetting the budget growth in expand and enterprise priority is a decrease in sustain assets, which have a 2025 budget of $193.3 million, a decrease of $24.9 million from the 2024 budget of $218.2 million. While the District invests a larger percentage of the capital portfolio on enterprise priority and expand projects, the level of investment in sustain assets is decreasing but is still approximately $7.4 million greater than the historical investment rate.

Transmission and Distribution is budgeted at $338.6 million, a decrease of $17.6 million or 4.9% from the 2024 budget. The decrease is largely due to 2024 budgeted investments in owned solar generation that did not materialize, partially offset by additional investment in enterprise priorities, particularly Resource Adequacy and Master Facilities Plan as the District builds out transmission and distribution infrastructure to support new generation and invests in improved facilities.

Production increased to $330.6 million from the 2024 budget spend of $261.3 million. The change of $69.3 million or 26.5% is primarily related to the net impact of decreased spending on Power with Purpose projects as those units are expected to come online in 2024, offset by investments in new combustion turbines that is ramping up in 2025.

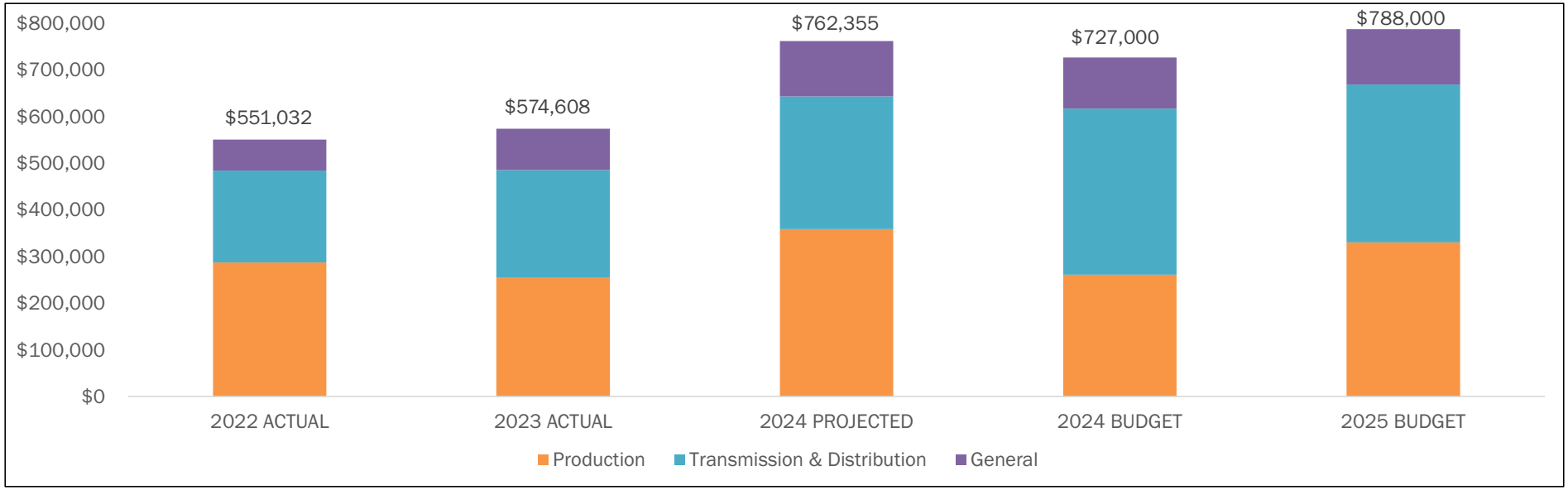
General for 2024 is budgeted to be $118.8 million, which is $9.2 million or 8.4% higher than the 2024 budget. The increase is the result of investment in Next Generation Grid as the District prepares to implement advanced metering infrastructure technology.

OMAHA PUBLIC POWER DISTRICT
2025 CORPORATE OPERATING PLAN

CAPITAL EXPENDITURES
(DOLLARS IN THOUSANDS)

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET $ CHANGE	% CHANGE
TRANSMISSION AND DISTRIBUTION	$ 197,344	$ 230,381	$ 284,302	$ 356,176	$ (71,874)	$ 338,625	$ (17,551)	(4.9)
PRODUCTION	287,260	255,580	359,190	261,259	97,931	330,586	69,327	26.5
GENERAL	66,428	88,647	118,862	109,565	9,297	118,789	9,224	8.4
TOTAL	**$ 551,032**	**$ 574,608**	**$ 762,355**	**$ 727,000**	**$ 35,355**	**$ 788,000**	**$ 61,000**	**8.4**

NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.



CAPITAL EXPENDITURES (DIRECT)
SIGNIFICANT PROJECT DESCRIPTIONS AND HIGHLIGHTS
(Dollars in Thousands)

RECOMMENDED PROJECTS:	2024 Projection	2025 Budget
Near Term Generation Support generation and transmission & distribution for Board Resolution No. 6582 approved on August 15, 2023	$ 149,360	$ 269,671
Master Facilities Plan Investment and upgrades to various OPPD facilities, which are all over 30 years old with only minor enhancements throughout their life	45,785	107,150
Circuit and Substation Upgrades Upgrade and replace multiple circuits and substations due to the expansion of our transmission and distribution infrastructure	61,951	82,076
AMI - Smart Grid Technology to support AMI	34,830	66,265
Transformer Purchases and Replacements Procure transformers to replace aging equipment and support load growth	31,522	30,777
Power with Purpose Support generation and transmission & distribution for Board Resolution No. 6351 approved on November 14, 2019	147,228	21,816

CAPITAL EXPENDITURES (DIRECT)
SIGNIFICANT PROJECT DESCRIPTIONS AND HIGHLIGHTS
(Dollars in Thousands)

RECOMMENDED PROJECTS:	2024 Projection	2025 Budget
Customer Service Residential Project Purchase and installation of underground or overhead infrastructure to new residential developments	$ 18,934	$ 18,432
Transportation Fleet Replacement Routine replacement of OPPD-owned transportation equipment, including light, medium and heavy duty trucks and construction equipment	16,383	18,007
Transmission Distribution Improvement Program-Cable Replacement Replace the worst performing underground distribution cable on a performance driven basis	16,548	15,645
North Omaha Extension Supports continued operation of North Omaha Station	10,690	13,292
Customer Service Commercial and Industrial Project Purchase and installation of underground or overhead infrastructure for commercial and industrial customers	13,182	13,157
Ground Line Inspection and Treatment Pole Replacement Replace degraded wood poles and structures used for transmission and distribution	7,945	11,019

CAPITAL EXPENDITURES (DIRECT)
SIGNIFICANT PROJECT DESCRIPTIONS AND HIGHLIGHTS
(Dollars in Thousands)

RECOMMENDED PROJECTS:	2024 Projection	2025 Budget
Subscription Software Renewals Renew subscription based software used by the district to conduct business	$ 4,767	$ 10,631
Transmission Distribution Improvement Program-Conductors Replace junk conductors on a performance driven basis	6,893	10,088
Transmission and Distribution Street & Highway Project Relocation of OPPD transmission and distribution facilities that are located in public road right-of-way	10,501	10,000
Coal Handling Upgrade Update Nebraska City coal handling system to reduce single point failure possibility	1,258	7,149
Expansion of Computing Storage Allows for real time expansion of computing capacity to allow for growth and support OPPD strategic initiatives	-	5,859
Energy Marketing Trade System OPPD will migrate the Energy Marketing and Trading processes to an industry standard	-	5,075
Substations and Control Centers Security Upgrades Security modifications required to address identified threats and vulnerabilities at various substation and control centers	12,887	4,946

CAPITAL EXPENDITURES (DIRECT)
SIGNIFICANT PROJECT DESCRIPTIONS AND HIGHLIGHTS
(Dollars in Thousands)

RECOMMENDED PROJECTS:	2024 Projection	2025 Budget
Arbor Railroad Line Improvements Repair and replace bridges, ties, ballast, rail, and crossings along the OPPD owned Arbor Rail line	$ 18,021	$ 4,832
Transmission and Distribution Street Light Project Relocation of OPPD street lights facilities that are located in public road right-of-way	3,500	3,500
Nebraska City Common Intake Vacuum Lift System Supports continued operation of Nebraska City at low river levels	-	3,150
Cass County Combustion Inspection Perform manufacturer recommended inpsection and repairs	-	2,950
Bellevue Transmission Redesign Improve the reliability and resiliency of the Bellevue transmission system	876	2,860
Large Motor Capital Repairs Support planned and emergent motor rewinds and replacements	-	2,800
Generation Station Intake Structure Environmental Upgrade Replace existing traveling screens (circulating water intake structure) at North Omaha and Nebraska City Fossil locations for renewal of the environmental permit	2,462	2,405

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Omaha Public Power District

Rate Fundamentals Report

EXHIBIT
G

Disclaimer

The statements made reflect OPPD's opinion and are intended strictly for educational purposes. The materials are intended to provide transparency in rate design and fundamental cost-of-service principles utilized in rate setting by OPPD. Some examples have been simplified for accessibility.

Agenda

I. Introduction
II. Total Cost Determination
III. Cost of Service Study
IV. Rate Design

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I. Introduction

Introduction

Report Goal

OPPD wants our customers to have foundational knowledge of how their rates are structured. This report provides information on how rates are calculated, set annually, and designed to align customer expectations and OPPD's strategic vision. This report connects the Corporate Operating Plan (COP), Strategic Initiatives, and Cost of Service Study (COSS) to help customers understand how these work together in establishing rates.

The following represents the goals of the information contained within this report:

- Introduce electricity basics
- Provide information on OPPD's Total Cost Determination (also referred to as the Revenue Requirement)
- Illustrate the steps performed in an embedded COSS with visibility to key modeling decisions
- Discuss alignment of costs with the fundamental rate elements – demand, energy, and service charges
- Bring visibility to OPPD's strategic vision for rate design

Introduction

Overview of the Rate Process



How large is the pie?

Total Cost Determination

- Determine the total costs required to provide service to our customers.



How to slice the pie?

Cost of Service Study

- Assign the total costs based on the relative contribution of each customer class to the cost drivers.



How to serve the pie?

Rate Design

- Recover the costs with rates that adhere to generally-accepted rate principles.

Introduction
Key Terms and Definitions

Generation	The production of energy via coal, natural gas, and renewables to satisfy peak demand and energy needs of our customers.
Transmission	Transmission of energy via high-voltage supply facilities, power lines, and substations that bring power from the generation source into our service territory.
Distribution	Distribution of energy via facilities and wires that connect the supply of energy to our customers.
Customer Services	Support services for all customers regardless of energy consumption (i.e. billing, metering, data management, customer service, etc.).

Introduction
Key Terms and Definitions

Cost of Service	The process of fairly apportioning the total costs to each customer class based on the relative proportion of their contribution to the costs.
Total Cost Determination	The total cost determination ensures that revenues cover the total costs to serve our customers and support our operations. This is also referred to as the Revenue Requirement.

Introduction
Key Terms and Definitions

Demand Costs	Costs based on the customer's highest amount of power (demand), measured in kilowatts (kW).
Energy Costs	Costs based on the customer's cumulative energy needs, measured in kilowatt-hours (kWh).
Customer Costs	Costs based on the number of customers on the system, measured in customer-months.

Introduction

The Electric Delivery System

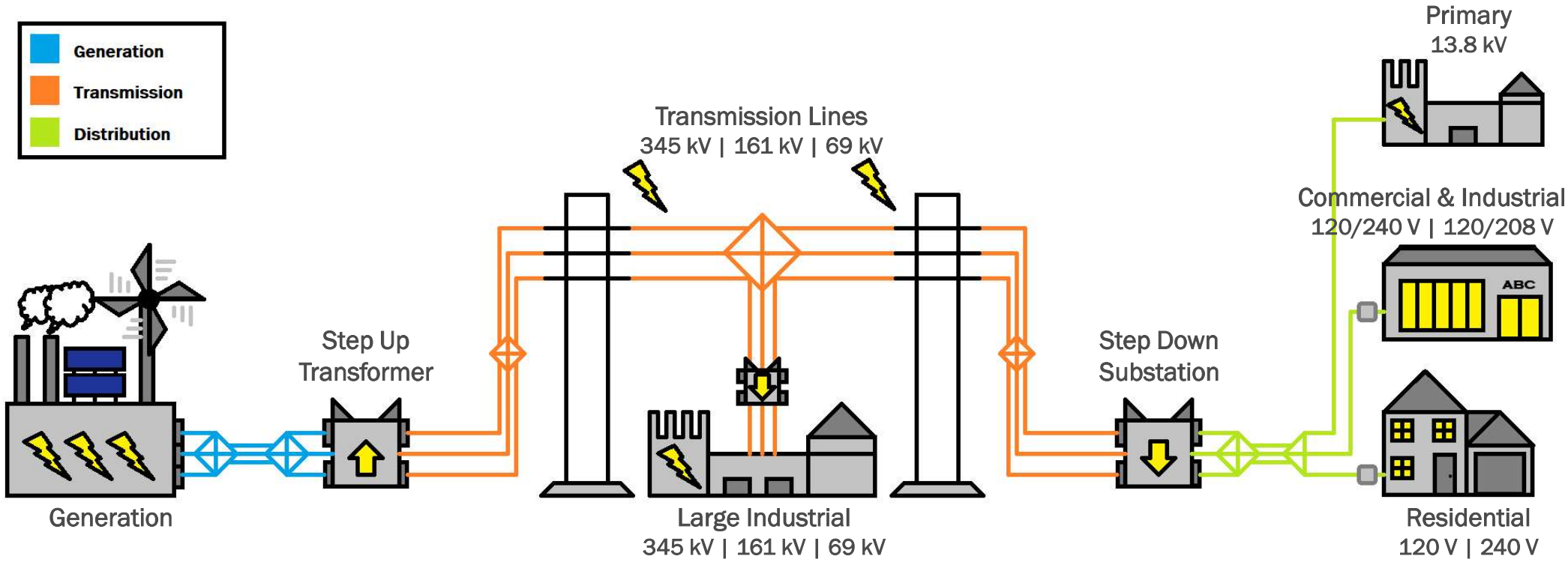


Illustration based off of the following source:

Office of Electricity Delivery and Energy Reliability. (2015, July). *United States Electricity Industry Primer*. U.S. Department of Energy. Retrieved January 2023, from https://www.energy.gov/sites/prod/files/2015/12/f28/united-states-electricity-industry-primer.pdf

Introduction

Electricity Basics: Generation

- Generation is the conversion of energy resources into electricity.
- Energy resources include coal, gas, renewables, and other forms.
- Each energy resource has a different ability to meet various energy needs and usage.
- Resource planning decisions include evaluating load growth expectations, resource adequacy, system resiliency, and cost effectiveness, while also taking into consideration OPPD's Pathways to Decarbonization.



Introduction

Electricity Basics: Generation by Source

- Fuel source is an important factor in generation.
- Fuel sources are typically categorized as renewable vs non-renewable.
- As outlined in the strategic visions of the *Powering the Future to 2050*, OPPD has a net carbon zero goal for 2050.
- By the end of 2024, OPPD's nameplate capacity consisted of 32.4% wind resources, up 5% year over year.

Introduction

Electricity Basics: Generation by Flexibility

- Dispatchable refers to the ability for a generation resource to change its output based on demand (within its generation potential).
- Dispatchable firm resources include technologies like conventional coal thermal, gas-fired combined cycle and combustion turbine, nuclear, geothermal, biomass, and others.
- Some renewable technologies are fully dispatchable such as nuclear and geothermal, while others such as wind and solar are dispatchable but limited to their variable fuel supply (referred to as variable energy resources).
- The ability to control generation output is critical for resiliency as severe weather, localized grid emergencies, and other extreme events can impact customers.
- OPPD's resource planning mix balances the ability to withstand and recover from localized and regional events with securing energy resources and maintaining a diverse portfolio of assets.

Introduction

Electricity Basics: Generation by Usage

- Generation facilities are often categorized by their intended purpose and utilization into the following usage categories:
- **Baseload** refers to facilities that are intended to run around the clock. Baseload units serve the minimum level of demand on the electrical grid over all hours of the day. Typically, these facilities have low fuel costs, but are less flexible to variations in demand.
- **Intermediate** refers to units that run a substantial portion of the year, but not the whole year. Combined-cycle gas units have historically filled this role.
- **Peaker** refers to units that are only utilized during peak hours. Typically, these units have higher fuel costs or economic costs, such as demand response.

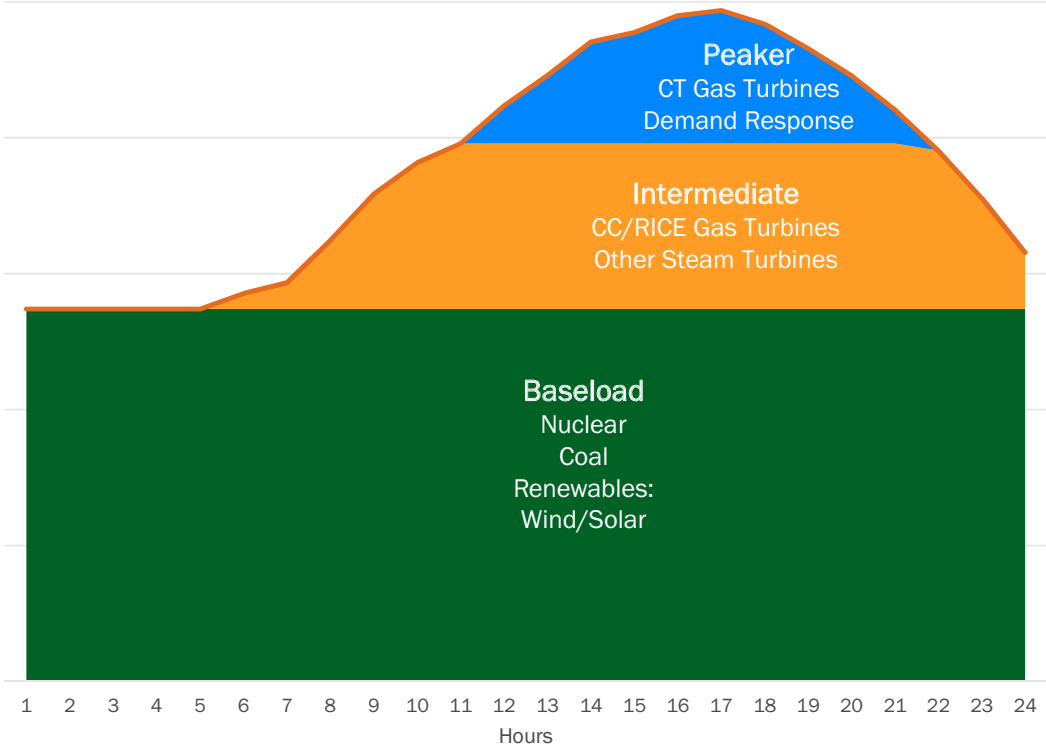


*Chart pictured is for illustrative purposes

Disclaimer on Peaker Resources:
Peaker Resources have historically operated as strictly serving peak load as the name would suggest. However, Peaker Resources currently operate as both serving peak load and balancing renewable resources.

Introduction

Electricity Basics: Transmission

- The transmission system is comprised of high-voltage lines (69kV, 161kV, & 345kV) that transfer bulk electricity between generation facilities and the end customer.
- Transmission lines are typically above ground with large support towers.
  - Air acts as the insulator with higher voltages requiring larger clearance.
  - Higher voltages reduce line losses.
- Some of the largest customers interconnect at the transmission level.
- For resiliency, each load point on the system generally has at least two alternate supply sources.



Introduction

Electricity Basics: Transmission (Cont.)

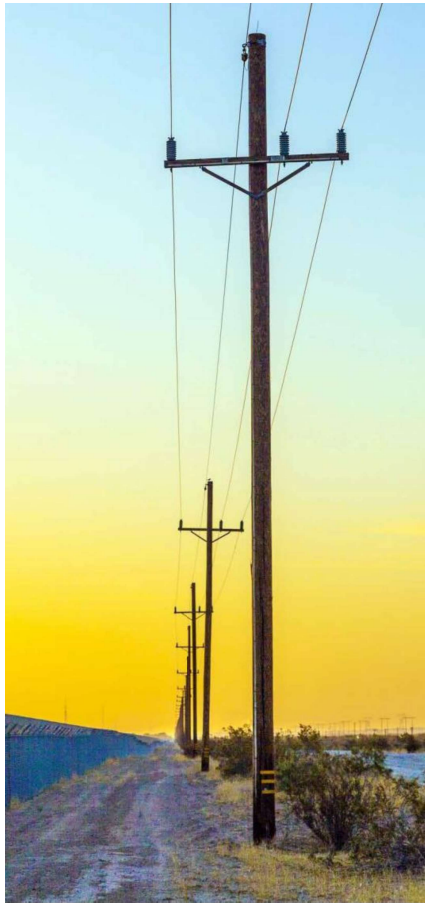
- OPPD's transmission system interconnects both to its generating stations and to neighboring utilities.
- OPPD's transmission system is part of the Eastern Interconnection and is a part of the Southwest Power Pool (SPP).
- SPP oversees regional transmission expansion for the OPPD region and guides the transmission service processes within our service territory.
- Altogether, the interchange of power over the transmission system has oversight by several national and regional entities that help ensure the reliability of the transmission system.



Introduction

Electricity Basics: Distribution

- The distribution system receives power from the transmission system.
- This power is brought down from high-voltage levels through distribution substations to a level that can be used by households and businesses.
- Most customers take service at the distribution level.
  - Primary Level – e.g. 13.8 kV (Three Phase) & 8 kV (Single Phase)
  - Secondary Level – e.g. 120V/240V or less than 600V
- The distribution system consists of the poles, transformers, substations, meters, service drops, and other assets needed to connect service to customers.



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II. Total Cost Determination

Total Cost Determination

Covering our Costs to Serve

- The total cost determination ensures that revenues cover the costs to serve our customers and support our operations, which is commonly referred to as the **Revenue Requirement**.
- The total cost determination is established by Strategic Directive 3 (SD-3), which provides the guiding principles to maintaining a low-cost, flexible structure to support the operation of the utility.
- The main principle established in SD-3 is maintaining a minimum 2.0 Debt Service Coverage Ratio.

$$\text{Debt Service Coverage Ratio} = \frac{\text{Revenues} - \text{Expenses}}{\text{Debt Interest} + \text{Principal Payments}}$$

Total Cost Determination

Capital Expenditure Philosophy

- The Debt Service Coverage Ratio is an important metric in evaluating the health of the utility.
- Maintaining the 2.0 Debt Service Coverage Ratio contributes to OPPD preserving a AA credit rating with the credit rating agencies.
- It ensures that new debt will be issued at competitive bond rates, which lead to lower long-term electricity rates for our customers.
- While Debt Service Coverage is an important consideration, there are other metrics that credit rating agencies consider when evaluating the bond rating. Likewise, OPPD's capital expenditure philosophy and investment decisions extend beyond credit rating agency evaluations.
- When making resource decisions, OPPD considers many factors such as reliability, economic development, competitive rate position, cost, etc.

Total Cost Determination

Return on Investments

- While OPPD does not set a minimum return on its investments on behalf of its customers, OPPD is required by state statute to set rates sufficient to establish and maintain a successful operation that does not incur operating losses (Nebraska Revised Statute 70-655).
- As a publicly-owned utility, any earnings above operating costs are strictly to ensure debt obligations are sustainably funded and investments are not deferred to future customers. Thus, returns are utilized to meet the needs of current customer-owners and support of operations.

Total Cost Determination
Strategic Investments

- OPPD is entering one of the most transformative resource planning eras in its 75-year history as capacity and energy needs grow and the industry evolves.
- OPPD's service territory is experiencing rapid growth in energy needs due to our competitive rates and economic development.
  - For example, peak load increased from 2,545 MW in 2022 to 2,811 MW in 2024
- OPPD remains committed to deliver on its Power with Purpose initiative:
  - 81 MWs of solar added in May 2024 (Platteview Solar Facility)
  - In Q1 2025, OPPD will add ~600 MWs of gas generation (Turtle Creek and Standing Bear Stations)
  - The utility also remains committed to planned North Omaha Station units 4 & 5 conversion from coal to natural gas, and retirement of units 1-3.
- OPPD's Near Term Resource Planning Goals support:
  - 1,000 – 1,500 MW of wind and solar (including 300 MW Milligan Wind Facility added Fall 2024)
  - 125 MW of battery storage
  - 32+ MW of demand response
  - 320 MW of added fuel capacity and fuel oil storage

Total Cost Determination

Planning Process Considerations

While the Integrated Resource Plan (IRP) details the comprehensive work in determining the resource planning strategy, several key considerations are listed below.

- Access to Credit Markets
- Reliability and Resiliency
- Cost Minimization
- Environmental Sensitivity
- Competitive Rate Position
- Economic Development
- Customer Experience
- Strategic Alignment

Total Cost Determination

Putting It All Together

- The total cost determination supports the overall needs of our system and ensures OPPD's operations remain favorable to credit rating agencies for the issuance of debt to finance investments.
- The total cost determination is driven by the standard established in SD-3 to maintain a minimum 2.0 Debt Service Coverage Ratio.
- OPPD's capital expenditure philosophy ensures that a balanced approach is taken regarding resource decisions to secure access to credit markets, maintain competitive rates, and support the overall health of the system.

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III. Cost of Service

Cost of Service

Embedded Cost of Service Study

- After the Total Cost Determination is complete, we move to the Cost of Service Study (COSS).
  - Total Cost Determination – *How large is the pie?*
  - Cost of Service Study (COSS) – *How do we slice the pie?*
- OPPD utilizes an embedded-cost approach, which is the most common approach in the industry.
- An embedded-cost approach utilizes accounting costs associated with assets and expenses as they occur to provide service.

Cost of Service

Study Goals

- Nebraska Revised Statute 70-655 requires the Board to establish rates that are fair, reasonable, and non-discriminatory.
- The goal of the COSS is to fairly apportion the total costs to each customer class based on the relative proportion of their contribution to those costs.
- There are three fundamental steps in performing an embedded COSS:
  - Functionalization
  - Classification
  - Allocation
- For each fundamental step, the COSS seeks to determine cost causation to appropriately assign costs to each rate class.
  - i.e. What was the cost driver?

Cost of Service
Overview

- The COSS goes through functionalization, classification, and allocation to ensure the costs of providing service are fairly and reasonably apportioned.
- Functionalization separates the utility's assets according to how they are used – generating electricity to meet demand and energy needs, transferring electricity from the power source to the distribution system, and distributing the power to OPPD's customers' premises. Billing and metering is included in distribution.
- Classification provides measures for the service level of each of the functionalized components.
  - Customer demand is measured in kilowatts (kW),
  - Customer energy is measured in kilowatt-hours (kWh)
  - Customer counts are measured in the number of customers (can be a weighted measure)
- Allocation then applies the classification metrics to each rate class.

Cost of Service

Step 1: Functionalization

- **Functionalization** refers to the process of dividing the total costs into three components:
  - Generation
  - Transmission
  - Distribution
- Functionalization is an important step as customers have various electrical service needs:
  - Distribution assets are primarily utilized by residential and commercial customers.
  - Large industrial customers interconnect at the transmission level.
- Proper functionalization ensures that rates are appropriately assigned based on cost causation and characteristics.

Cost of Service

Functionalization FERC Standards

- The process of functionalizing the total costs is straightforward as it typically follows the assignment according to the accounting treatment as set forth in the Uniform System of Accounts (USOA) from the Federal Energy Regulatory Commission (FERC).

Functionalization According to FERC USOA		
Asset Account Number	Item	Expense Account Numbers
300s - 340s	Generation	500s - 550s
350s	Transmission	560s - 570s
360s - 370s	Distribution	580s - 590s

Cost of Service

Functionalization General Categories

Generation

- Fuel, purchased power, and generation assets

Transmission

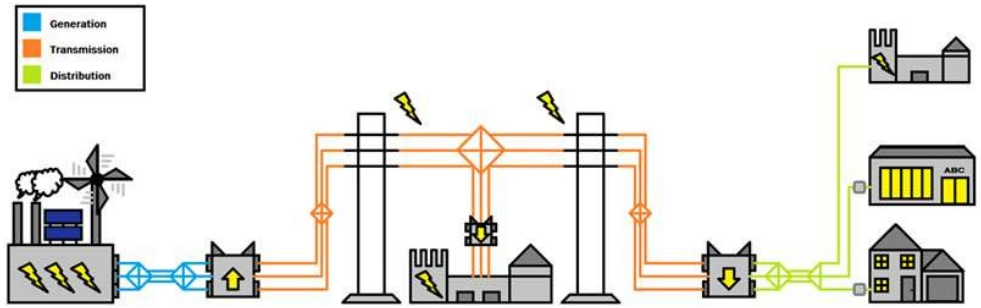
- High-voltage transmission lines (69kV, 161 kV, 345 kV)
- Transmission substations

Distribution

- Distribution substations
- Distribution lines (primary and secondary)
- Overhead and underground services
- Poles
- Meters, service drops, feeders
- Streetlights
- Customer service

General

- General plant and administrative and other general (Needs to be distributed to generation, transmission and distribution)



Cost of Service
Functionalization Transformation

- OPPD is undergoing a transformative period:
  - 1,000 – 1,500 MW of wind and solar
  - 125 MW of battery storage
  - 32+ MW of demand response
  - 600 – 950 MW of combustion turbines
  - 320 MW of added fuel capacity and fuel oil storage
- Changes in our generation mix, growing energy resource needs, and expansion in our residential, commercial, and industrial classes will result in the functionalized total costs evolving over time.
- OPPD will continue to monitor anticipated changes, economic changes, and other factors to maintain gradualism and rate stability.

Cost of Service

Step 2: Classification

- **Classification** identifies the drivers of the costs.
- Costs are generally split into three categories:
  - **Demand Costs**
    - Costs based on the customer's maximum demand
    - Measured in kilowatts (kW)
  - **Energy Costs**
    - Costs based on the customer's energy needs
    - Measured in kilowatt-hours (kWh)
  - **Customer Costs**
    - Costs based on the number of customers on the system
    - Measured using customer-months
- Portions of general plant and administration and general expenses are each categorized as energy-related, demand-related, and customer-related.

Cost of Service

Classification Demand-Related Costs

- Demand-related costs are costs that vary based on the size-related needs to serve a customer's maximum demand.
- All three functionalization categories have size-related needs.
  - Generation costs are the capacity built to meet maximum expected demand and the additional planning reserve margin.
  - Transmission costs are mainly size-related demand costs as transmission facilities transmit bulk power to load centers to meet maximum expected demand.
  - Distribution costs also have size-related demand costs including transformers and conductors to meet maximum expected demand. Customer classes do not have their maximum demands at the same times on the distribution system.

Cost of Service

Classification Energy-Related Costs

- The majority of energy-related costs are generation costs. While some generation assets are built for resiliency and peak demand, generation is also built to serve the energy needs of customers and portions are assigned to energy.
  - The split for generation assets between energy and demand will be discussed in detail below.
- Costs that vary with energy production are categorized as energy-related. Two major cost categories:
  - Fuel is classified entirely as energy-related as energy needs require the consumption on fuel.
  - Purchased power is generally classified as energy-related because power is purchased on the integrated marketplace when OPPD is short energy resources or when market prices are lower than OPPD's variable fuel costs.

Cost of Service

Classification Customer-Related Costs

- The majority of customer-related costs are distribution costs.
- Customer-related costs includes meters, customer billing, and portions of the distribution plant.
- The split between demand-related and customer-related distribution costs is determined by OPPD's minimum system approach.
- In 2022, OPPD reviewed the classification of its distribution system and enacted the minimum system methodology for its planning system. More information will be discussed in detail below.

Cost of Service

Classification Important Considerations

- Two important classification factor decisions are:
  - The split between demand-related and energy-related generation assets.
  - The split between customer-related and demand-related distribution assets.
- The best strategy for determining the classification approach in an embedded-cost approach is identifying cost causation and system planning.
- OPPD utilizes a load factor approach (a derivative of the “average and excess” approach) for the classification of generation assets.
  - OPPD performed a study considering 14 different demand classification approaches when determining the classification of generation assets.
- The load factor approach uses the system wide load factor to determine the proportion assigned to energy-related costs and the remaining portion is assigned to demand-related costs.
  - Rather than the traditional “excess demand” derivation for the demand-related allocation, the 4CP measure is used (more information provided in allocation section below).
- As previously mentioned, OPPD’s generation fleet will change considerably in the future. Additionally, the Inflation Reduction Act of 2022 has significantly impacted the business decisions regarding the owning of utility-scale renewable resources. OPPD will ensure that the classification of generation assets matches the transformation of the generation portfolio.

Cost of Service

Classification Important Considerations (Cont.)

- The classification of the distribution plant is another important consideration (particularly FERC accounts 364–370).
- OPPD has previously used the zero-intercept, but adopted the minimum system approach in 2022 determining it best represented OPPD's system planning.
  - The minimum system approach provides a more intuitive approach to determining the customer-related distribution costs as it assigns a minimum-sized unit cost as the customer-related portion and the remaining costs are assigned as demand-related.
- The minimum system approach was one of many classification, functionalization, and allocation refinements OPPD recently implemented in collaboration with our rate consultant Brattle.
  - These adjustments resulted in greater precision of cost recovery matching cost incurrence for demand, energy, and customer costs.

Cost of Service

Step 3: Allocation

- **Allocation** is the assignment of the classified costs to customer classes based on the relative proportion of their contribution to those costs.
- Allocation is the most critical step of a COSS as it determines the cost allocations for each customer class.
  - It is essential to understand the characteristics of each customer class, such as the number of customers, energy consumed, voltage-level, and their contribution to both coincident peak (CP) and non-coincident peak (NCP) demand.
- Each allocation method represents a set of relative proportions that total to 100% across all customer classes.
- There are multiple allocations used for the various classified costs:
  - Demand-related allocations
  - Energy-related allocations
  - Customer-related allocations

Cost of Service

Allocation Approaches

- Before discussing allocation approaches, it is worth noting certain customer classes will view some allocation approaches more favorably than others.
- OPPD's allocation approach is based on a set of measurable criteria that are universally adopted for determining the appropriateness of an allocation method.
- Some of these criteria include:
  - Measuring the precision of the method compared to the actual planning and operating of facilities.
  - Measuring the accuracy of the method to cost causation.
  - Assessing the ability of the method to recognize specific customer class characteristics, such as energy usage, peak demand, number of customers, etc.
  - Assessing the accuracy of the method to produce consistent results.
  - Reviewing the modernity of the method to reflect best practices across the industry.
- Adhering to these criteria, several methods can be appropriate. OPPD partners with Brattle to provide a balanced approach in selection of allocation methods.
- OPPD does not seek to influence a particular set of results when determining allocation factors.

Cost of Service
Allocation Methods

- Demand-related allocation methods:
  - Coincident peak demand (CP)
    - Also referred to as system peak demand (kW)
    - Depending on the nature of the CP, there are different measures of CP (4CP vs. 12CP)
  - Non-coincident peak demand (NCP)
- Energy-related allocation methods
  - Aggregate energy (kWh)
  - Considered both at point of generation and point of use to account for energy losses
- Customer-related allocation methods
  - Number of customers
  - Weighted customer measures:
    - Relative cost – meters, transformers, service lines, etc.
    - Effort required – customer service, billing, etc.
    - Ratio of service – transformers, connections, streetlights, etc.

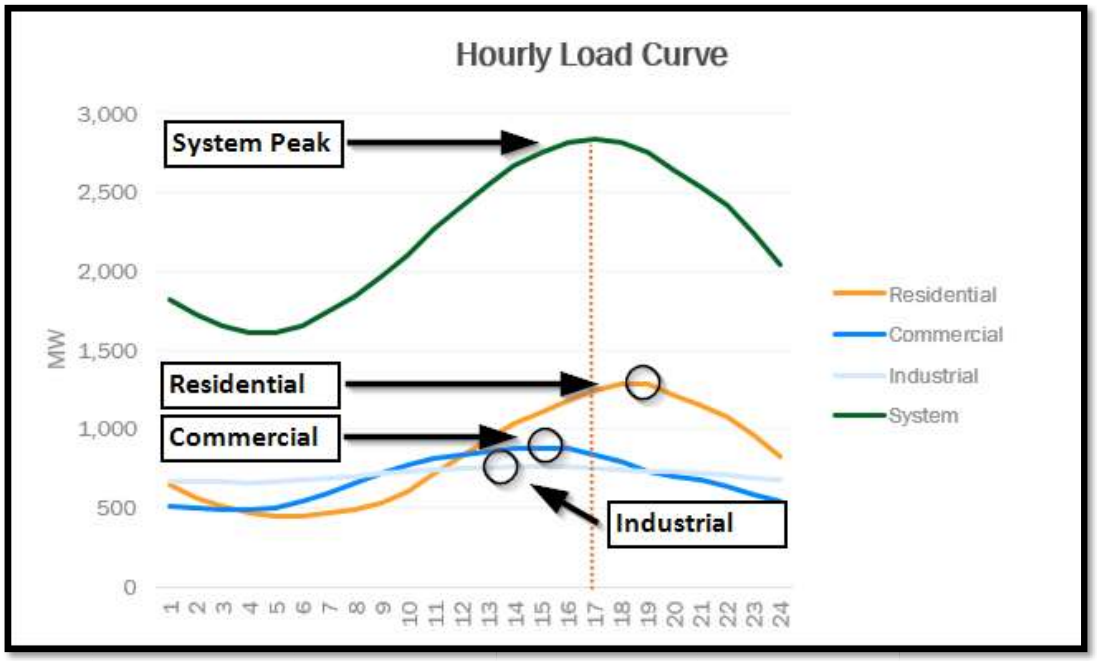
Cost of Service
Demand-Related Allocations

- Coincident Peak (CP) is the demand placed on the system by a customer class at the system peak.
- 4CP measures the CP contribution during the 4 highest months of the year.
  - These are the summer months of June – September for OPPD.
  - This method is used to allocate the demand-related production costs as our capacity and OPPD's resource adequacy requirement is currently driven by the summer peak. Note: resource adequacy requirements may change as SPP examines system resiliency requirements and may cause a need to reevaluate the 4CP allocation for demand-related production costs.
- 12CP measures the contribution during the system peak hour of each of the 12 months of the year.
  - These are averaged together to provide the 12CP measure.
  - 12CP is widely accepted in allocating transmission costs as it strikes a balance in reflecting the way the system has been planned and is used. This helps to maintain reliability and serve load accordingly.
- Non-coincident peak (NCP) refers to the demand placed on the system by each customer class at the point in time when that class reaches its individual peak demand (regardless of the system peak).
  - This measure is utilized for the allocation of distribution demand-related costs such as substations, which are built to meet the highest instantaneous peak demand regardless of the time of day.

Cost of Service

Load Curve

- The following graph provides an example of a daily load curve cycle and visually illustrates the concept of CP and NCP.
- The **circled points** for each class indicate the **NCP** for each class, while the intersection of each class line with the **dotted line** illustrates their contribution to the **CP** (system peak).
- None of the NCP's align with the CP. However, load variability is distinct between classes. In summer months, generally:
  - Residential peaks in the evening
  - Commercial peaks middle afternoon
  - Industrial peaks early afternoon
    - Industrial is relatively constant throughout the day
- Variability translates to different levels of utilization of system capacity. Load Factor measures utilization efficiency and is important for determining allocation of costs for each class.



Cost of Service
Load Factor

- Load Factor is a measure that captures variation in load.
- It is calculated as the ratio of average load by peak load:
  - $\text{Load Factor} = \frac{\text{Average Load}}{\text{Peak Load}}, [0,1]$
- Higher load factors indicate higher utilization over all hours of the day and year, which aligns well with baseload generation.
- Baseload generation typically has lower energy costs and higher load factor customers align well with baseload generation (leading to lower rate offerings).
- Differences in load factors can occur within rate classes and can merit different rate offerings based on different levels of utilization of the system.

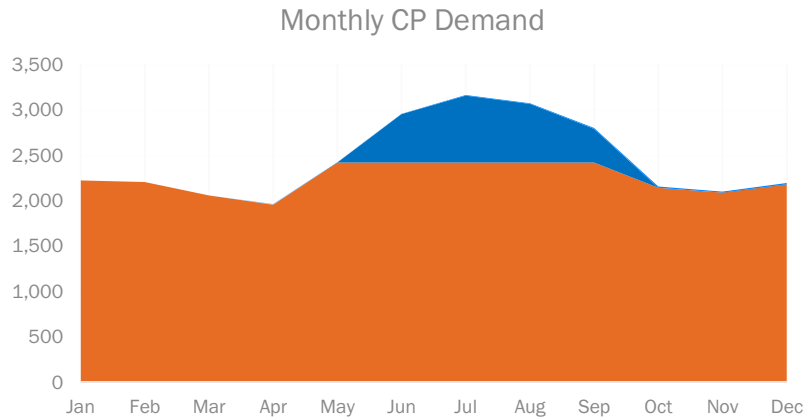
Cost of Service

Load Factor Impacts on Rates

- Rate 110 (Standard) and Rate 115 (Heat Pump) are both residential rates, but with different load profiles due to Rate 115 requiring an electric heat pump.
  - Rate 115 uses electricity both in heating and cooling of the household, yearly load factors are typically 35% higher than Rate 110 customers.
  - With more load used throughout the year, rates are lower and the average Rate 115 pays approximately 2.2 cents/kWh less than the average Rate 110 customer.
- Electrification of households will allow more efficient recovery of costs and illustrates how load factor is correlated with rates.
- Electrification of transportation can be utilized to increase load factors. Rate offerings will be evaluated to incentive recharging over night (off-peak periods), which would be beneficial to the system. However, if left unaddressed, customer load factors may worsen if charging occurs during on-peak periods.

Cost of Service

Generation Demand-Related Allocations



- OPPD utilizes a derivative of the average and excess approach for classification with the “excess demand” allocation method being 4CP.
- The rationale for utilizing 4CP is illustrated in the monthly peak load graph above.
  - The blue area represents the summer peak demand in excess of the non-summer peak demand (orange area).
  - Therefore, generation capacity and OPPD’s resource adequacy requirement is currently driven by the summer peak.

Cost of Service

Transmission Demand-Related Allocations

- Transmission costs are classified as entirely demand-related using the 12CP allocation.
- The 12CP allocation method is widely accepted as the most appropriate approach for allocation of transmission costs. This is due to the majority of utilities planning their systems to meet their 12 monthly peaks.
  - FERC uses 12CP in allocation of transmission costs.
  - SPP also relies on 12CP for allocation of fees from its members.

Cost of Service

Distribution Demand-Related Allocations

- The 1NCP allocation method is widely accepted and utilized as the distribution demand-related allocator.
  - Transformers, substations and other size-related distribution investments are generally designed for customer's maximum demand needs regardless of the system peak.

Cost of Service
Energy-Related Allocations

- There are several substantial cost categories allocated strictly on energy-related usage including:
  - Fuel
  - Purchased power
  - Portions of generation assets
- Energy is measured in usage at the meter, production at the facility, and adjusted for losses on the system (line, substation, transformer, etc.).
- OPPD captures where customers are located on the system and determines load losses at each interconnection level.
  - Customers interconnected at higher voltage levels have lower energy losses (industrial).
  - Customers interconnected at lower voltage levels have higher energy losses (residential).

Cost of Service

Energy-Related Allocations (Cont.)

- When customers use power is another important factor.
  - Fuel costs are different for different generation types.
  - Purchased power is higher during specific time intervals and seasons.
- Seasonality (summer vs non-summer) for residential and commercial classes provide a means of capturing time of consumption impacts.
- Advanced Metering Infrastructure (AMI) will further enable the ability to provide time-varying rates and better match cost recovery with incurrence.

Cost of Service
Customer-Related Allocations

- Customer-related allocation methods typically involve a weighted-measurement of the number of customers, which controls for variation in customer attributes.
- Customer-related allocation methods include measures such as:
  - Relative cost – meters, transformers, service lines, etc.
  - Effort required – customer service, billing, etc.
  - Ratio of service – transformers, connections, streetlights, etc.
- Customer-related costs are the smallest classified cost category.
- Distribution systems represent the most diverse functional component and require special attention to ensure proper classification and allocation.

Cost of Service

Transmission Level Market Access Rate Allocations

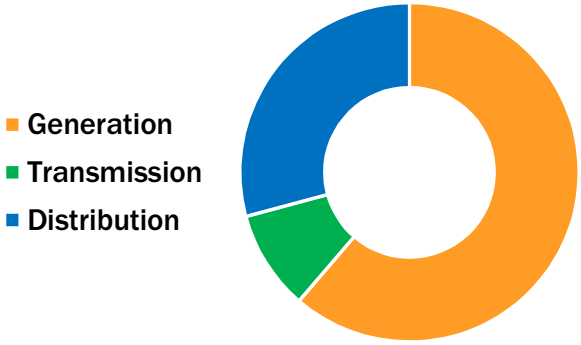
- Large Power – High-Voltage Transmission Level – Market Energy, Rate 261M, reflects a unique customer class and offering.
  - As required, customers are supplied at transmission level voltage 161kv or 345kV and own their own electric substation for the delivery of service.
  - In addition, customer's energy charge is equal to wholesale market prices for energy from the SPP for each hour and these prices are directly passed through to the customer.
- Rate 261M customers have unique allocation factor assignment in the energy components:
  - Each customer receives a direct assignment of the purchased energy costs at the market price.
- The interconnection level is considered in the allocation of functional components.
  - Interconnection at the transmission level avoids much of the distributional investments.
- This unique offering provides a shared risk and investment between the customer and the utility that requires specific allocation considerations.

Cost of Service

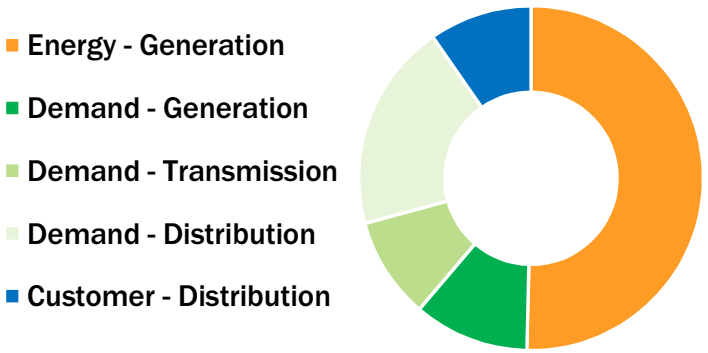
Summary of OPPD Cost of Service Allocations

- The following charts are examples of the proportion of the total costs to serve by functionalization, classification, and main allocation method.

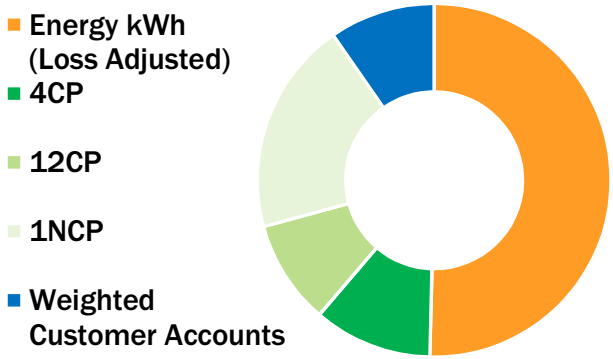
Functionalization



Classification



Allocation



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OPPD
Omaha Public Power District

IV. Rate Design

Rate Design

Step 4: Rate Design

- The ultimate goal of the COSS is to fairly apportion costs among customer classes based on their proportionate contribution to the costs.
- After determining the total costs for each customer class, cost recovery is aligned with the fundamental rate elements/charges:
  - Demand Costs (Demand Charges)
    - Costs based on the customer's maximum demand
    - Measured in kilowatts (kW)
  - Energy Costs (Energy Charges)
    - Costs based on the customer's cumulative energy needs
    - Measured in kilowatt-hours (kWh)
  - Customer Costs (Service Charges)
    - Costs based on the number of customers on the system
    - Measured using customer-months

Rate Design

Demand Charges

- Demand charges are determined through dividing the demand-related costs by the billing demand (measured in kW).
- Demand charges include the size-related capacity costs of generation, transmission, and distribution.
  - Demand charges must be consistent with the collection method of demand meter data to ensure over/under collection does not occur.
- Demand charges seek to provide price signals to customers regarding instantaneous use costs and serve to more effectively recover demand-related costs based on peak contributions.
- When a class does not have demand metering technology, demand-related costs must be recovered either through:
  - The energy charge or
  - The service charge
- This is discussed below regarding 2-Part Rates vs. 3-Part Rates.

Rate Design
Energy Charges

- Energy charges reflect recovery of energy costs.
- Energy charges can take the form of both **Base Rates** and **Riders**.
  - **Base Rates** are charges set within the service regulations and approved by the Board.
  - **Riders** (sometimes referred to as "trackers") are additional charges, not included in the base rates, that are designed to recover specific costs that the rider is "tracking,"
    - **Rider 461** - OPPD utilizes a Fuel and Purchased Power Adjustment Rider (FPPA) that recovers fluctuations in net power costs (fuel, purchased power, and off-system sales) outside of OPPD's control. This rider ensures the base rates remain stable during volatility in the integrated marketplace while also providing an effective price signal to customers.
  - Energy charges can be structured in several different ways:
    - Seasonally – based on the time of year
    - Temporally – based on the time of day or week (AMI-enabled)
    - Volumetrically – based on the volume consumed (e.g. declining-block structures)

Rate Design
Service Charges

- Service charges are used to recover the costs of being a customer.
- Service charges are uniform for all customers taking service on a rate and do not vary based on size-related demand or energy needs.
  - Includes costs such as billing, customer service, meters, etc.
- Service charges are calculated as follows:
  - $$\text{Service Charge} = \frac{\text{Customer Costs Allocated to Customer Class}}{\text{Number of Customers in Class} \times 12 \text{ Billing Months}}$$

Rate Design

2-Part Rates vs 3-Part Rates

- OPPD's residential and small commercial classes lack the supporting infrastructure for demand charges. Therefore, demand-related costs are recovered through service charges and energy charges.
  - Rate offerings with only service charge and energy charges are referred to as **2-Part Rates.**
  - Rate offerings with an additional demand charge component are referred to as **3-Part Rates.**
- For these classes, the energy charge must recover not only energy costs but also generation, transmission, and distribution costs. Increasing diversity of customer needs has made it challenging to effectively recover fixed costs in the absence of time-of-use volumetric energy charges.
  - Customer class divergence includes:
    - Various forms of energy efficiency
    - Electrification of heating
    - Electrification of transportation
    - Customer-owned generation
- OPPD's 2-Part rate structures recovers portions of distribution demand-related costs and the customer-related costs within the service charge while demand-related generation, transmission, and part of distribution costs along with energy costs are recovered through the energy charges.
- OPPD's transition towards more effective price signaling will take a balanced approach over time.
  - In the interim, as we transition to AMI technology, OPPD will seek to align legacy rates with future price signals.
  - This will allow for stability and behavioral shifts in energy consumption that will mitigate transitional challenges.

Rate Design

Generally-Accepted Rate Principles

- There are some generally-accepted rate principles utilized within the electric industry, which include:
  - Customer bill stability
  - Simplicity, understandability, and transparency of rates
  - Rates that support healthy utility operations
  - Rates that promote efficient use and investments
  - Fairness in allocation among classes
- These principles must be properly understood to remain effective in the shifting landscape of energy, which includes:
  - Ongoing technological advancements
  - Growth in distributed energy resources (DER)

Rate Design

Transition Toward Effective Price Signals

- Utility planning has become increasingly sophisticated, and the ability to capture allocators based on more granular load and equipment data has enabled greater precision when determining class-level costs to serve.
- It is also important to adhere to the Efficient-Use Principle, which is defined as providing customers with effective price signals and information to manage their energy costs.
  - Appropriate changes in energy usage will result in a reduction in the costs allocated to them. For example, in the future with AMI-enabled technology, customer interactions will increase in app-based communications, which provide real-time cost savings estimates to encourage more efficient consumption.
- While high-load factor customers have historically matched baseline generation, as the industry moves increasingly towards intermittent renewable generation, customers with flexible demand will be key to the minimization of costs and therefore benefit from incentives and rate offerings.

Rate Design

Transition Toward Effective Price Signals (Cont.)

- AMI technology will be initiated over the next several years and will help OPPD to build more advanced and dynamic rate structures.
- Enabled by this technology, customers will have greater understanding of the drivers of their bill and better ability to respond to price-signals.
  - OPPD will be able to utilize data from AMI-metering to better serve our customers by coordination of customer profiles and usage data allowing for strategic engagement that address customer's needs and preferences.

Rate Design
Conclusion

- Rate design aligns cost recovery with the fundamental rate element – demand charges, energy charges, and service charges.
- Rate principles provide the guiding vision and long-term strategy to provide customers with greater flexibility, choice, transparency, gradualism, affordability, and fairness when determining rate offerings.
- The utility industry is experiencing rapid developments. Rate structures will need to be able to evolve to be more adaptable to the increasingly dynamic environment and leverage technology that will become available to better serve our diverse customer needs.
- OPPD will continue its partnership with both external entities and our customer-owners to provide affordable, reliable, and environmentally sensitive energy services to our customers.

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CLIENT/MATTER NUMBER
142173-0101

April 22, 2025

White & Case, LLP,
609 Main Street, Suite 2900
Houston, Texas 77002

RE: ***First Requests for Production of Documents in Connection with Zachry Holdings, Inc. et al. v. Omaha Public Power District (Adv. Pro. No. 25-03025 (MI))***

Dear Ms. Garr:

I am writing in response to your letter dated April 18, 2025, regarding Zachry's Voluntary Requests for Production of Documents.

As the Court has made clear, discovery is not currently open. OPPD does not believe that it is appropriate for Zachry to serve discovery requests while a motion to transfer venue remains pending and as we prepare to file an amended motion to dismiss. Attempting to initiate discovery at this stage is not only premature—it disregards the procedural posture of this case.

Even assuming the Court ultimately denies our forthcoming motion to dismiss, discovery would still be improper in this forum. The Southern District of Texas Bankruptcy Court is not the appropriate venue for this dispute, and OPPD will not voluntarily engage in discovery in this Court. Doing so would risk waiving significant objections to this venue.

Furthermore, Zachry's attempt to carve out limited discovery tailored solely to its own objectives is plainly self-serving. Discovery—when appropriate and in the proper forum—must encompass all relevant issues, not just those Zachry selectively identifies. The effort to control the scope and timing of discovery undermines the fairness of this process.

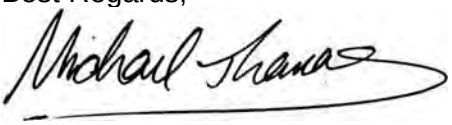
Zachry has repeatedly represented to the Court that the liquidated damages issue involves a straightforward legal issue suitable for early resolution via summary judgment. If that were truly the case, discovery would be unnecessary. The fact that Zachry is now seeking to open discovery only undercuts its own narrative and confirms that its claims are not as clear-cut as it has led the Court to believe.

We trust that this matter is now clear. Should you wish to discuss this further, please feel free to reach out.

EXHIBIT
H

FOLEY & LARDNER LLP

Best Regards,



Jonathan Michael Thomas

IN THE UNITED STATES BANKRUPTCY COURT
FOR THE SOUTHERN DISTRICT OF TEXAS
HOUSTON DIVISION

In Re:	§	Chapter 11
ZACHRY HOLDINGS, INC., et al.,[1]	§	Case No. 24-90377 (MI)
Debtor	§	(Jointly Administered)
ZACHRY HOLDINGS, INC.	§	
Plaintiff,	§	
v.	§	Adversary No. 25-03025 (MI)
OMAHA PUBLIC POWER DISTRICT	§	
Defendant	§	

DECLARATION OF TANYA BODELL

I, Tanya Bodell, pursuant to 28 U.S.C. § 1746, declare under penalty of perjury that the following is true and correct:

1. I make this declaration in support of the Motion for Partial Summary Judgment on Liquidated Damages filed by Zachry Holdings, Inc., ("Zachry") in the above-named matter. I make the statements of fact in this declaration of my own personal knowledge, research, and analyses. If called as a witness in this proceeding, I could testify competently to the facts set forth herein.

2. I am a Partner with StoneTurn, a global professional services firm. I lead StoneTurn's energy and sustainability practice for business advisory, regulatory support, and litigation services. StoneTurn is a global advisory firm that provides consulting services, forensic accounting and investigative services, compliance and monitoring, data analytics, forensic technology, and litigation consulting services to companies, their counsel, and regulators. StoneTurn professionals serve clients from 14 global offices across five continents.[2]

[1] Zachry, https://zachrygroup.com/

[2] For more information, see StoneTurn's website: www.stoneturn.com. See StoneTurn, "Office Locations,"

3. For more than 30 years, I have advised market participants, new entrants, government officials, regulators, and lawyers on commercial, regulatory, and policy issues. For energy market participants and new entrants, I provide strategic advice informed by advanced analytics on asset valuation, investment strategy, mergers/acquisitions, restructuring, regulatory outreach, and market analysis. I also advise market participants, regulators, and market operators on competitive energy market design, and have led the development and application of energy market models to analyze each of the three wholesale electricity market interconnects in North America. I have analyzed energy and other commodity trade books during my career, including those of electric utilities, energy marketers, and financial firms engaged in physical and financial trading.

4. I provide independent expert testimony and support in restructuring, regulatory, and litigation cases pertaining to the energy industry, including assessment and valuation of benefits and damages claimed for breach of contract, fraudulent misrepresentation, and market manipulation, among other issues. I regularly provide industry insight, publish in industry journals, and speak on energy industry trends.

5. I received an MBA as a Sloan Fellow from Massachusetts Institute of Technology in 2008; a Masters in Public Policy from the Harris School of Public Policy, University of Chicago, *with honors*, in 1993; and a Bachelor of Arts Degree in Mathematical Economics from Pomona College, *magna cum laude*, in 1991.

6. I have the following current and prior energy affiliations:

   a) Northeast Energy Commerce Association, President Emeritus
   b) New England Women in Energy and the Environment, Member
   c) International Chamber of Commerce, Vice Chair, Center for Expertise
   d) Energy Bar Association, Non-legal Member
   e) Town of Cohasset, Alternative Energy Committee, Chair (2010 – 2013; 2019 – present); Advisory Committee (2013 – 2019)

7. **Exhibit A** provides my curriculum vitae, which summarizes these qualifications and professional experience, including testimony and articles published within recent years.

8. StoneTurn is compensated at an hourly rate of $795 for my services in connection with this matter. I am assisted by several StoneTurn professionals working under my direction. Neither StoneTurn's nor my compensation is dependent upon the conclusions reached in this matter or its outcome.

9. I have been asked to offer opinions on: (i) the scope of estimated economic damages incurred by Omaha Public Power District ("OPPD") from delay in "Substantial

Accessed: October 30, 2024; StoneTurn, "Practice Areas," Accessed: October 30, 2024.

Completion"[3] of the Turtle Creek Station and Standing Bear Lake Station (individually referred to as "Facility" and collectively "the Facilities"); (ii) whether economic damages were readily ascertainable when Amendment No. 2 was executed; (iii) how potential economic damages from delay in Substantial Completion of the Facilities could have been determined when Amendment No. 2 was executed; and (iv) to provide a forward-looking estimate of anticipated economic damages starting at the updated Guaranteed Substantial Completion Date in Amendment No. 2, as of the date when that amendment was signed.

10. In developing my opinions, I have relied on: (i) my education, training, and professional experience; (ii) information produced by Zachry in this matter; (iii) information obtained through independent research, peer-reviewed articles, and other publicly-available sources; and (iv) industry data, including electricity and natural gas prices.

11. I understand that Zachry has requested, but not received, information from OPPD concerning its electricity purchases and other actions taken to address peak demand during the delay in Substantial Completion of the Facilities. If and as additional information becomes available, I reserve the right to modify or supplement my opinion and this declaration accordingly.

I. Executive Summary

12. OPPD is a publicly-owned electric utility and political subdivision of the state of Nebraska. As a public power district, OPPD supplies electricity to the residents, businesses, and government entities located in its service territory. In order to meet its electricity supply obligations, OPPD procures power products and services from third parties, including the Southwest Power Pool ("SPP"), and operates its own power plants to provide those products, such as electrical energy, capacity, and ancillary services (in combination referred to as "Electricity Products").

13. SPP is an Independent System Operator ("ISO") that operates a high voltage transmission system and centralized markets for Electricity Products, in the central United States, and serves parts of Nebraska, including Omaha. OPPD is a market participant in the SPP system.[4]

14. As a general matter, electricity must be generated and consumed across a transmission system instantaneously. The integrity of the power grid relies on SPP to balance supply and demand; failure to do so results in outages and an unreliable system. In order to ensure there is sufficient power generation available to meet peak demand, SPP imposes generation capacity reserve requirements on each of the load serving entities that rely on the SPP system for supply.[5] Starting in 2023, OPPD was required to maintain Planned

[3] Substantial Completion is defined in the original EPC Contract, Article II, p. 6. Liquidated Damages are defined as a charge per calendar day delay in the event Guaranteed Substantial Completion Date is not achieved.

[4] SPP, https://www.spp.org/about-us/members-market-participants/

[5] SPP, 2024 SPP Resource Adequacy Report, p. 2.

Reserve Margins ("PRM") at least equal to 15 percent of its customers' peak demand for electricity.[6] In order to meet the PRM for its projected electricity load obligations, OPPD regularly has to make the decision of whether to buy or build new generation capacity.[7]

15. In September 2021, OPPD entered into an Engineer, Procure, and Construct Contract ("Original EPC Contract") with Zachry to build two separate power generating stations:

1) Standing Bear Lake Station, consisting of nine reciprocating engines totaling 150 MW;[8] and

2) Turtle Creek Station, consisting of two combustion turbines totaling 450 MW.[9]

16. OPPD stated that it expected each power station to operate only 15 percent of the time,[10] during periods when electricity demand is the highest, referred to as peak periods of demand. This expected level of operation is best suited for the chosen generation technologies, which are more widely used as intermediate or peaking units as opposed to baseload units that have a more efficient heat rate and would be more economic to operate most of the time.

17. For each of the Facilities, the Original EPC Contract specifies a Guaranteed Substantial Completion Date and liquidated damages for delays ("Liquidated Damages") if the station is not online by that date. Amendment No. 1, entered into on November 9, 2023, extended the Guaranteed Substantial Completion Dates and increased the daily charge for delay. During Zachry's bankruptcy negotiations, Zachry and OPPD entered into Amendment No. 2 to the Original EPC Contract on August 1, 2024,[11] which extends the Guaranteed Substantial Completion Date further from the original and amended provisions, and increases the daily charge for delay to levels above those established by Amendment No. 1.

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https://www.spp.org/documents/71804/2024%20spp%20june%20resource%20adequacy%20report.pdf

[6] OPPD, https://www.oppdcommunityconnect.com/power-with-purpose

[7] This obligation and planning requirement is required for nearly all load serving entities across power systems around the world. As a result, there are standard industry practices for projecting the economics of alternative resources and electric utilities regularly engage in integrated planning studies that project future demand for electricity and analyze alternative resource investments that could meet that demand going forward.

[8] OPPD, https://www.oppdcommunityconnect.com/standing-bear-lake-station

[9] OPPD, https://www.oppdcommunityconnect.com/turtle-creek-station

[10] Ibid.

[11] IN THE UNITED STATES BANKRUPTCY COURT FOR THE SOUTHERN DISTRICT OF TEXAS HOUSTON DIVISION In re: ZACHRY HOLDINGS, INC., *et al.*,1 Debtors., Chapter 11, Case No. 24-90377 (MI) (Jointly Administered), OMAHA PUBLIC POWER DISTRICT'S APPLICATION FOR ALLOWANCE OF ADMINISTRATIVE EXPENSE CLAIM, Case 24-90377 Document 2176 Filed in TXSB on 02/14/25, p. 5.

18. I understand that, as of the date of this report, the Facilities are connected to the SPP transmission system and able to operate,[12] but have not been granted a certificate of Substantial Completion by OPPD. OPPD claims that the Liquidated Damages provisions apply and, in a filing to the bankruptcy courts, provided a calculation from the contracted start dates to February 15, 2025 totaling $38 million.[13] This value does not incorporate the accelerated Liquidated Damages provision for Turtle Creek effective on February 15, 2025 that would increase the Liquidated Damages to 10 percent of the total Second Amended EPC contract cost, or around $42.8 million for Turtle Creek Station alone.

19. If the Liquidated Damages provisions are carried forward, the combined cap of 15 percent of the Second Amended EPC Contract value would apply before Standing Bear Lake Station would reach its cap on Liquidated Damages.

20. By my calculation, the overall Liquidated Damages cap of 15 percent of the Second Amended EPC Contract value, or $64.3 million, was reached on February 20, 2025.[14]

21. I have analyzed the Liquidated Damages provisions as well as the estimated economic damages that OPPD has incurred since the contractual start date through the filing of this report. My opinions are as follows:

    1) **Liquidated Damages significantly exceed estimated economic damages that OPPD incurred:** The Liquidated Damages provisions represent an implied rate that is much higher than the estimated damages incurred by OPPD, and is not a reasonable estimate of economic damages.

    2) **Amendment No. 2 pushed Liquidated Damages even further away from underlying economic fundamentals.** The fact that the daily charge for the liquidated damages provisions increased by $100,000 per day when moving from a start date in May 2023, right before the peak season, to December 2024, when the plants would be less likely to operate, indicates an even more extreme separation from economic damages conditions that OPPD would be expected to incur.

    3) **The implied energy and capacity prices in the Liquidated Damages provisions are exorbitantly high:** The daily charge for Liquidated Damages is not a reasonable estimate of the market price for energy that would have been generated by the Facilities, or the value of additional generation capacity that the Facilities would provide to meet

[12] OPPD website, https://www.oppdcommunityconnect.com/standing-bear-lake-station/news_feed/update-april-8-2025; OPPD website, https://www.oppdcommunityconnect.com/turtle-creek-station/news_feed/april-9-2025-update-2

[13] Ibid.

[14] I have not analyzed and have not formed any opinions on allocation of or responsibility for delay, including what portion, if any, of the liquidated damages are allocable to delays caused by Zachry, OPPD or any other third parties. To avoid debate about attribution, I estimate damages for the entire period of delay for the Facilities for comparison to the Liquidated Damages for that same period.

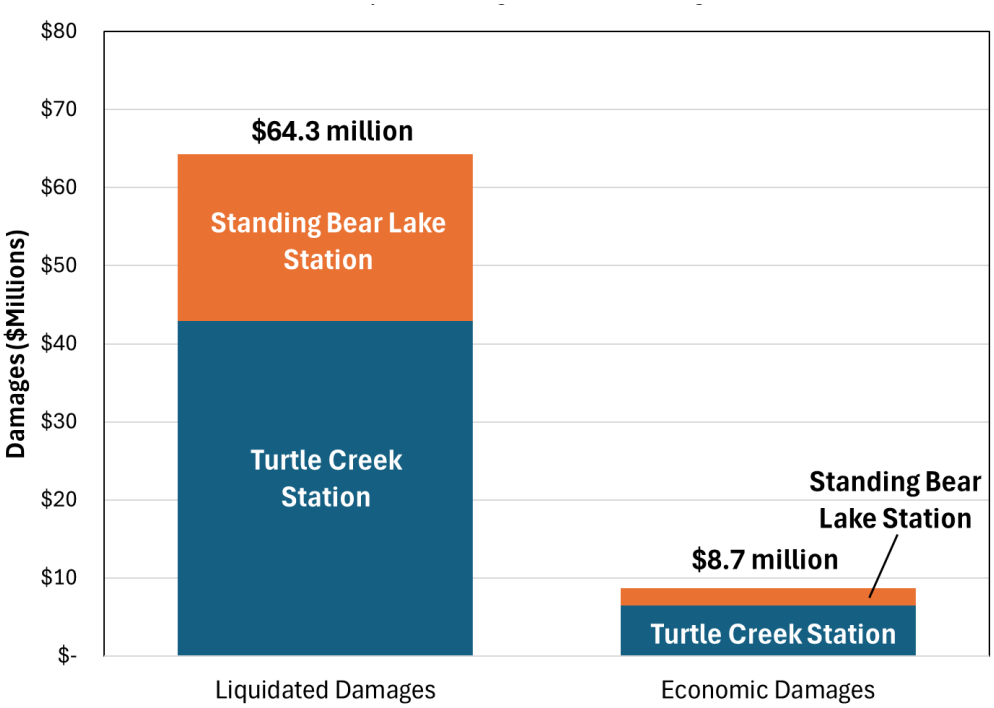
OPPD's reserve requirements. The price for Electricity Products implied by the daily charge for Liquidated Damages indicate a disconnect from the economic value of a delay in Substantial Completion.

4) **Liquidated Damages do not reflect the estimated economic damages OPPD incurred:** OPPD may have incurred damages based on the difference in value between what the Facilities would have provided to OPPD if they had been operational versus the replacement costs of the Electricity Products that OPPD had to purchase (or did not have excess to sell) in the absence of the Facilities being Substantially Complete. However, the Liquidated Damages do not reflect or provide a reasonable estimate of the lost economic value of the Facilities.

5) **Economic damages incurred by OPPD are straightforward to estimate.** I calculate damages based on publicly-available information on market prices to estimate the value of the Electricity Products that OPPD had to procure due to the delayed operations of the Facilities. Public information on fuel costs and variable operations and maintenance costs also are available to estimate what OPPD would have spent if the Facilities had been operational. I have used this approach to calculate damages in multiple cases where power generating facilities were delayed or cancelled. It is an accepted methodology for calculating such damages tied to the incremental costs incurred by OPPD had the Facilities been Substantially Complete by the Guaranteed Substantial Completion Date.

6) **Liquidated Damages are over 700% higher than economic damages.** Using this standard industry methodology, I calculate estimated damages for the period December 17, 2024 through April 15, 2025. Under this methodology, I estimate economic damages to be $8.7 million, significantly less than Liquidated Damages, which are at the contractual cap of $64.3 million -- over 7 times the damages that OPPD incurred due to the delayed start date. This value can be easily updated to reflect the period ending when the Facilities receive their certificate of Substantial Completion in accordance with the Second Amended EPC Contract (**Figure 1**).

Figure 1: Liquidated Damages vs Economic Damages (December 17, 2024–April 15, 2025)[15]



7) **OPPD should have been able to project anticipated economic damages using standard industry practices.** Electricity industry market participants, including OPPD, regularly project the economics of alternative buy versus build decisions. Every five years, OPPD has produced an Integrated Resource Plan that incorporates such calculations to choose whether to buy or build new plants.[16] Market operators, including the Southwest Power Pool ("SPP") regularly use projections of the cost of new entry and projected energy and ancillary services revenues to calculate the net cost of new entry. Assessing the value of a power plant as the difference between the market value of its Electricity Products versus the production cost to produce those Electricity Products (i.e., net revenues or operating margins) is a common practice in the industry.[17] I would be very surprised if OPPD does not perform similar types of

[15] Damages for Turtle Creek starts on December 17, 2024 and for Standing Bear Lake on December 31, 2024 per the Guaranteed Substantial Completion Dates in the Liquidated Damages provisions in the Second Amended EPC Contract.

[16] OPPD, 2016 OPPD Integrated Resource Plan, p. 12, https://www.oppd.com/media/318210/2016-oppd-integrated-resource-plan.pdf; OPPD, 2021 OPPD Integrated Resource Plan, p. 10, https://www.oppd.com/media/245413/oppd-integrated-resource-plan.pdf. I understand that OPPD currently is engaged in a new integrated resource planning process to project its procurement needs for the next twenty years.

[17] A regular estimate of net revenue is the spark spread, which represents the difference between energy prices and the cost of natural gas to produce that energy.

calculations or hire third parties to perform these types of projections and valuations as part of its planning processes to decide whether to buy versus build new power plants.

8) **Projected economic damages as of August 1, 2024, for the period of December 17, 2024 through April 15, 2025, are higher than estimated damages given various disruptions to the marketplace (e.g., pandemic, war and supply chain shocks), but substantially lower than Liquidated Damages for the same period.** Using market prices for energy, ancillary services, and capacity as set through centralized and bilateral markets, a reasonable estimate of potential damages can be developed based on information known or knowable the date that Amendment No. 2 was signed. Using this ex-ante approach results in projected economic damages of $15.2 million, well below what the Liquidated Damages calculation would be for the same time period.

22. Additional detail supporting my opinions is provided in this declaration and in the exhibits attached to this declaration. **Exhibit B** provides a list of documents relied upon and/or considered. **Exhibit C** includes a list of acronyms used within this report. **Exhibit D** describes the methodology used to calculate damages in more detail. **Exhibit E** summarizes the assumptions used in the calculation of damages.

II. Background

23. This section provides context that serves as the basis for my methodology and assumptions. The following is my understanding of the timeline of events, motivation for OPPD to enter into the Original EPC Contract, the technical specifications for the Facilities, and the provisions of the Second Amended EPC Contract that changed the Guaranteed Substantial Completion Date and daily charge for delay in meeting the Guaranteed Substantial Completion Date.

24. OPPD is responsible for supplying electricity to its approximately 413,500 electric utility customers (almost 1 million people), most of which are residential.[18] As a public power district, OPPD can service only electrical load within its service territory. The OPPD service area extends beyond just Omaha, covering a 13-county, 5,000-square mile service area in southeast Nebraska that includes the City of Omaha and adjacent territories, including the community of Carter Lake, Iowa.[19] OPPD publishes an annual report that describes its resources and resource requirements, as well as its financial position.[20] As a

[18] OPPD, 2024 Annual Report, "Building Our Legacy," Inside Cover, p. 0 and p. 94, https://www.oppd.com/media/320606/entire-2024-annual-report.pdf

[19] OPPD, 2021 Integrated Resource Plan, p. 8. OPPD's service territory includes the city of Omaha, Nebraska and adjacent territory comprising all of Douglas, Sarpy and Washington counties, along with portions of Cass, Saunders, Dodge, Otoe, Nemaha, Johnson, Paynee, Richardson, Burt and Colfax counties, as well as Carter Lake, Iowa which is connected to OPPD's Omaha distribution system.

[20] See for example, OPPD 2024 Annual Report, https://www.oppd.com/media/320606/entire-2024-annual-rport.pdf; OPPD 2023 Annual Report, https://www.oppd.com/media/319683/2023-entire-annual-report.pdf; and OPPD 2022

public power district, OPPD is governed by an elected board of eight directors[21] and is not subject to federal or state regulatory commission oversight with respect to its tariffs. That said, OPPD is required to meet certain reporting requirements at the state and federal levels, as well as with respect to its role as a market participant in SPP.[22]

25. OPPD is registered for a number of different functions with the North American Electric Reliability Corporation ("NERC"), including Distribution Provider ("DP"), Generator Owner ("GO"), Generator Operator ("GOP"), Resource Planner ("RP"), Transmission Owner ("TO"), Transmission Operator ("TOP"), and Transmission Planner ("TP").[23]

26. As an RP, OPPD is "The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific Loads (customer demand and energy requirements) within a Planning Authority area."[24] In this role, OPPD has the obligation to ensure it has sufficient supply of electricity to meet its load supply obligations.[25] Sufficient supply usually is measured in terms of meeting required reserves above and beyond peak load requirements. OPPD meets its load obligations through its own generation resources[26] and as a market participant in SPP.[27]

27. As an ISO, SPP is similar to the Electric Reliability Council of Texas ("ERCOT"), which operates the electric grid for the geographic area to the south of SPP[28], and the Mid-Continent Independent System Operator ("MISO"), which is responsible for the area to the east of SPP. Unlike ERCOT which operates in a single state, however, SPP operates an electricity transmission system serving all of the states of Kansas and Oklahoma, as well as portions of North Texas, Nebraska, Arkansas, Iowa, Louisiana, Minnesota, Missouri, Montana, New Mexico, North Dakota, South Dakota, and Wyoming. In its role as electric

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Annual Report, https://www.oppd.com/media/318975/2022-entire-annual-report.pdf.

[21] OPPD, 2024 Annual Report, Inside Cover, p. 0.

[22] OPPD, Service Regulations & Schedules, https://oppd.com/media/172612/oppd-rate-manual.pdf; OPPD, 2024 Annual Report, https://www.oppd.com/media/320606/entire-2024-annual-report.pdf

[23] NERC, NERC Active Compliance Registry Matrix as of April 22, 2025,https://www.nerc.com/pa/comp/Registration%20and%20Certification%20DL/NERC_Compliance_Registry_Matrix_Excel.xlsx

[24] NERC, "Appendix 5B, Statement of Compliance Registry Criteria (Revision 8)," Effective: June 27, 2024, www.nerc.com/AboutNERC/RulesOfProcedure/Appendix%205B%20eff%2020240627_signed.pdf

[25] Ibid., p. 6.

[26] OPPD, 2021 Integrated Resource Plan, Table 5-10 Load and Capability Report - Summer Peak (MW), p. 57, https://www.oppdcommunityconnect.com/irp

[27] SPP, https://www.spp.org/about-us/members-market-participants/ See also FERC approval of SPP's imposition of responsibility for maintaining adequate reserves on LREs at 184 FERC ¶ 61,207, at P 6 (2023), https://www.spp.org/documents/70245/20230929_order%20setting%20aside%20prior%20order%20in%20part%20-%20complaint%20regarding%20planning%20reserve%20margin_el23-40-001.pdf

[28] ERCOT, https://www.ercot.com/news/mediakit/backgrounder

system operator, SPP also functions as the market operator and coordinates centralized markets for Electricity Products, including electrical energy and the ancillary services required to support the high-voltage transmission system that delivers energy from generators to load. A variety of market participants buy and sell their electricity services through SPP, including generators and load responsible entities ("LREs") such as OPPD.[29]

28. LREs in SPP, including OPPD, are responsible under the SPP Open Access Transmission Tariff ("OATT") to "maintain adequate capacity to meet its Resource Adequacy Requirement (RAR)" for the peak summer season.[30] OPP is required to procure and maintain sufficient resources to meet its "RAR" -- a minimum level of reserve requirements sized to its load obligations.[31] Reserve requirements are based on the peak load requirements of their customers plus a defined reserve margin (e.g., 15 percent) above and beyond that peak demand. Reserve margins can be met with generation capacity that is either owned by an LRE or purchased from a third party.

29. As part of its system planning, OPPD decided to build new generation projects to meet its RAR.[32] OPPD put out a request for proposal in 2019, to which Zachry responded and was awarded the EPC Contracts for what are now referred to as the Standing Bear Lake Station and Turtle Creek Station.[33]

30. In its 2021 Integrated Resource Plan, OPPD identifies "Standing Bear" and "Turtle Creek" as providing 597 MW of peak generating capacity to contribute to its Planned Reserve Margin ("PRM"), which is projected to be slightly above 15.1 percent by 2024 (assuming the Facilities came online as originally planned).[34] At the time of the Integrated Resource Plan, SPP required 12 percent reserve margins,[35] which SPP has since increased to a 15 percent PRM in effect as of 2023.[36] In August 2024, SPP's Regional State Committee and

[29] SPP, "2024 SPP Resource Adequacy Report," Published on June 14, 2024, p. 37, www.spp.org/documents/71804/2024%20spp%20june%20resource%20adequacy%20report.pdf

[30] Ibid., p. 2.

[31] OPPD The Wire, https://oppdthewire.com/southwest-power-pool-oppd/#:~:text=SPP%20increased%20the%20planning%20reserve,15%25%20in%20the%20coming%20years; SPP, 2017 Resource Adequacy Report, p. 2, https://www.spp.org/documents/52237/june%202017%20resource%20adequacy%20report.pdf; SPP Attachment AA of SPP Tariff, p. 12, https://spp.org/documents/58597/attachment%20aa%20tariff.pdf.

[32] OPPD, https://www.oppdcommunityconnect.com/generation; OPPD, https://www.oppdcommunityconnect.com/standing-bear-lake-station; OPPD, https://www.oppdcommunityconnect.com/turtle-creek-station.

[33] OPPD, https://www.oppdcommunityconnect.com/standing-bear-lake-station?tool=qanda; OPPD, https://www.oppdcommunityconnect.com/turtle-creek-station.

[34] OPPD, 2021 Integrated Resource Plan, p. 57, https://www.oppdcommunityconnect.com/irp.

[35] Ibid., p. 29. SPP, 2017 Resource Adequacy Report, p. 2, https://www.spp.org/documents/52237/june%202017%20resource%20adequacy%20report.pdf..

[36] Ibid., p. 1. SPP, 2023 Resource Adequacy Report,

board approved a minimum PRM requirement of 16 percent for the summer and a 36 percent winter-season PRM.[37]

31. The Facilities provide OPPD with capacity reserves, but are only expected to operate during peak demand periods.[38] OPPD indicates that the Facilities are expected to operate 15 percent of the time.[39] Given that SPP is a summer peaking system,[40] I would expect that most of the production would occur during the summer months, with occasional production in the winter during extreme winter events.[41]

32. A summary of the specific characteristics for each of the Facilities are summarized below (**Figure 2**).

https://www.spp.org/documents/69529/2023%20spp%20june%20resource%20adequacy%20report.pdf; SPP, https://spp.org/documents/68838/20230216_deficiency%20response%20-%20revisions%20to%20add%20a%20process%20to%20allow%20an%20exemption%20of%20the%20deficiency%20payment_er23-636-001.pdf

[37] SPP, "SPP board approves new planning reserve margins to protect against high winter, summer use," August 6, 2024, www.spp.org/news-list/spp-board-approves-new-planning-reserve-margins-to-protect-against-high-winter-summer-use/

[38] "The units are intended to provide reliability to the system and are expected to operate at low capacity factors . . ." OPPD, 2021 Integrated Resource Plan, p. 3.

[39] OPPD, https://www.oppdcommunityconnect.com/standing-bear-lake-station; OPPD, https://www.oppdcommunityconnect.com/turtle-creek-station

[40] NERC, 2024 LTRA, pp. 55 – 59, "SPP peak load occurs during the summer season," p. 58, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf;

[41] SPP, "State of the Market Summer 2024," Published October 29, 2024, Updated October 31, 2024, Figure 2-1, p. 4, www.spp.org/documents/72602/spp_mmu_qsom_summer_2024_v2.pdf; OPPD, https://oppdthewire.com/high-el,ectric-bill-saving-tips-2/.

Figure 2: Facility Specifications

Characteristics	Standing Bear Lake Station	Turtle Creek Station
Number of Units	9	2
Capacity per Unit	16.7 MW	225 MW
Total Capacity[42]	150 MW	450 MW
Primary Fuel	Natural Gas	Natural Gas
Decarbonization Potential	15% hydrogen/gas blend	30% hydrogen/gas blend or biodiesel fuel
Technology	Reciprocating Internal Combustion Engines (RICE)	Simple Cycle Combustion Turbines
Brand	Wärtsilä 18V50DF RICE	Siemens Energy, Inc. SGT6-5000F CTs
Heat Rate[43]	6,500 – 8,500 mmBtu/MWh	8,000 – 10,000 mmBtu/MWh
Other	Fast start-up capability	Fast start-up capability

III. Liquidated Damages Provisions

33. In this section, I address the Liquidated Damages provisions and why they fail to reflect a reasonable estimate of economic harm from the delay of Substantial Completion of the Facilities

34. The Original EPC Contract, Amendment No. 1, and Amendment No. 2, each include Liquidated Damages provisions for each of the Facilities tied to failure to meet the Guaranteed Substantial Completion Date by Facility. These provisions include a daily charge for each day of delay, with Liquidated Damages capped by a percentage of the total contract cost (10 percent per Facility; 15 percent for both combined).

[42] The values reported by OPPD on its website and in its 2021 Integrated Resource Plan are slightly lower than the winter and summer rated capacity listed in the SPP Interconnection Queue:

Standing Bear Lake Station: 9 units at 18.84 MW each = 169.56 MW

Turtle Creek Station: 2 units at 255 MW each = 510 MW

SPP, Interconnection Facilities Study Report, GEN-2020-043, September 2022, GEN-2020-043 Facility Study FINAL.pdf

For purposes of calculating economic damages, I use the capacity values cited by OPPD.

OPPD, https://www.oppdcommunityconnect.com/turtle-creek-station; OPPD, https://www.oppdcommunityconnect.com/standing-bear-lake-station; OPPD. 2021 Integrated Resource Plan, https://www.oppdcommunityconnect.com/irp

[43] The thermal guarantees are redacted in the contracts. This range reflects a generalized range for the technology type as reported by Enerdynamics, Energy Knowledgebase, https://energyknowledgebase.com/topics/heat-rate.asp

35. Under Amendment No. 2, one month after the Guaranteed Substantial Completion Date, the Liquidated Damages daily rate ratchets up. Another month after that, an acceleration provision increases Liquidated Damages for each Facility up to the cap. In my opinion, the round-numbered increase of $100,000 per Facility in the daily delay charge and allowance for only two months of delay under Amendment No. 2, regardless of market conditions when the delay occurs, completely disconnects the Liquidated Damages provisions from economic harm actually incurred by OPPD. As a result, the Liquidated Damages provisions, on their face, are an unreasonable way to estimate economic damages.

36. On May 21, 2024, Zachry filed for bankruptcy protection under Chapter 11, Title 11 of the United States Bankruptcy Code.[44] Chapter 11 allows for a company to reorganize its debts while continuing operations.[45] As part of the bankruptcy proceedings, Zachry and OPPD renegotiated the EPC Contracts, resulting in Amendment No. 2 to the EPC Contracts.[46]

37. Amendment No. 2 delays the Guaranteed Substantial Completion Date from August 2024 (as provided for in Amendment No. 1) to December 2024, and increased the daily values for liquidated damages substantially,[47] as summarized in **Figure 3**.

[44] Zachry, Notice of Chapter 11 Bankruptcy Case, https://veritaglobal.net/zhi/document/249037724052100000000045.

[45] 11 USC Ch. 11: Reorganization, https://uscode.house.gov/view.xhtml?path=/prelim@title11/chapter11&edition=prelim

[46] Second Amendment, as referenced in IN THE UNITED STATES BANKRUPTCY COURT FOR THE SOUTHERN DISTRICT OF TEXAS HOUSTON DIVISION In re: ZACHRY HOLDINGS, INC., *et al.*,1 Debtors., Chapter 11, Case No. 24-90377 (MI) (Jointly Administered), OMAHA PUBLIC POWER DISTRICT'S APPLICATION FOR ALLOWANCE OF ADMINISTRATIVE EXPENSE CLAIM, Case 24-90377 Document 2176 Filed in TXSB on 02/14/25, p. 5.

[47] Engineer, Procure, and Construct Contract for Omaha Public Power District Standing Bear Lake and Turtle Creek Generating Stations, Contract No. 263406, September 21, 2021; Amendment No. 2 to Engineer, Procure, and Construct Contract for Omaha Public Power District Standing Bear Lake and Turtle Creek Generating Stations (Contract No. 263406), p. 4.

Figure 3: Comparison of Liquidated Damages Provisions Before and After Renegotiation

Characteristics	Original EPC Contract[48]		Amendment No. 1[49]		Amendment No. 2[50]	
Project Name	**SBLS**	**TCS**	**SBLS**	**TCS**	**SBLS**	**TCS**
Liquidated Damages	Daily Rate					
First Stage	$125,000	$50,000	$225,000	$150,000	$350,000	$250,000
Second Stage	$250,000	$100,000	$350,000	$200,000	$500,000	$400,000
Liquidated Damages Cap	10% of EPC Cost per Facility; 15% for both		10% of EPC Cost per Facility; 15% for both		10% of EPC Cost per Facility; 15% for both	
Contract Price	$366,207,836		$428,741,118		$428,741,118	
Guaranteed Substantial Completion Date	05/01/23	08/18/23	08/08/24	08/30/24	12/30/24	12/16/24
Second Stage Start	05/16/23	09/02/23	08/24/24	09/15/24	01/30/25	01/16/25
Acceleration Date	None	None	12/20/24	12/20/24	03/01/25	02/15/25

38. On February 14, 2025, OPPD filed a submission to the Bankruptcy Court that calculated Liquidated Damages from December 17, 2024 up to, but not including, February 15, 2025 for each of the Facilities.[51] OPPD's calculation of Liquidated Damages for this period totals $38 million.[52] If the period is extended one more day, Liquidated Damages for Turtle Creek Station would have increased to $42.9 million, due to the acceleration provision in the Liquidated Damages calculation. Extending the Liquidated Damages provisions forward, indicates that the combined cap of 15 percent of total contract value (i.e., 0.15 x $428.7 million = $64.3 million) was reached around a week later on February 21, 2024 (**Figure 4**).

[48] Ibid. Original EPC Contract, Article IV, Article XI, Exhibit E.

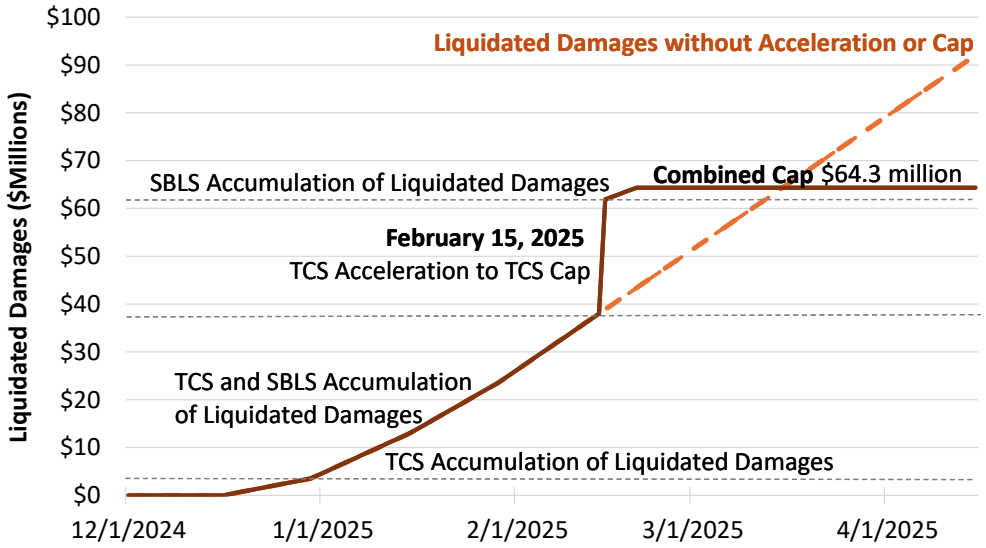
[49] Amendment No. 1 to Contract No. 263406, Para. 5, Exhibit E.

[50] Ibid. Amendment No. 2, Para. 7, Para. 8.

[51] OPPD Application for Allowance of Administrative Expense Claim, Case No. 24-90377, Document 2176. This calculation goes through February 14, 2024 and stops at the point where accelerated damages would have occurred for Turtle Creek Station. If the analysis had used the proper dates, I calculate that the total would have included the acceleration date and Liquidated Damages would have been $61.9 million instead of their filed claim for $38.0 million.

[52] Ibid. In stopping the calculation at the end of February 14, 2025, the calculation excludes the acceleration of Liquidated Damages to the cap for Turtle Creek Station.

Figure 4: Liquidated Damages for the Facilities at Different Dates per Amendment No. 2



39. To assess how the Liquidated Damages daily delay charge compares to economic damages, I calculated the implied price in the new Liquidated Damages Provisions for two Electricity Products: (i) energy; and (ii) capacity. I then compare those values to market prices during the damages period as described in more detail below.

1) **Implied Energy Value:** I calculate the implied value for energy by taking the daily rate for Liquidated Damages after the first month and dividing by the average anticipated daily energy production (assuming a 15 percent capacity factor). The use of a 15 percent capacity factor for the winter months likely understates that value given that the SPP peak period, when the Facilities would operate the most, is likely to occur in the summer months.

2) **Implied Capacity Value:** I calculate the implied capacity value of each Facility by taking the daily delay charge and dividing by the total nameplate capacity of the Facilities converted to kilowatts per month.

Figure 5 displays the value of capacity and energy implied by the Liquidated Damages daily rate after the first month of delay.

Figure 5: Implied Price for Energy and Capacity in the Liquidated Damages Value

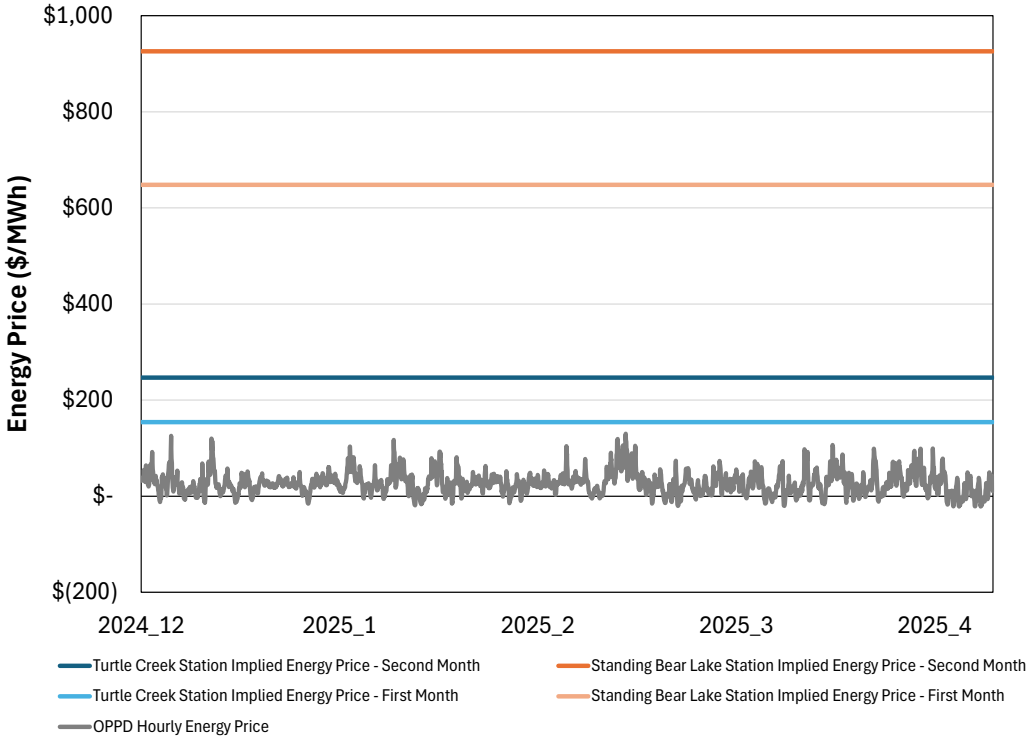
Characteristics	**Amendment No. 2**	
Project Name	**Standing Bear Lake Station**	**Turtle Creek Station**
Liquidated Damages Daily Rate After the First Month of Delay	$500,000	$400,000
Implied Energy Price ($/MWh)[53]	$919	$251
Implied Capacity Price ($/kW-month)	$100	$28

40. The implied energy and capacity prices in the daily rate for Liquidated Damages are significantly higher than the market value for those Electricity Products.

41. As shown in **Figure 6**, the implied energy price, assuming only revenues from energy production) in the Liquidated Damages price is well above any hourly price for energy in the SPP market for the delay period from December 2024 through February 2025. The blue line represents the hourly price for electrical energy being traded in SPP during the damages period. The gray lines represent the implied energy price ($/MWh) in the Liquidated Damages daily rate for Standing Bear Lake Station (first month and thereafter). The orange lines represent the implied energy price ($/MWh) for Turtle Creek (first month of delay and thereafter). The fact that the orange and gray lines are so much higher than the actual energy price settled in SPP at the OPPD load node indicates how disconnected from economic damages the liquidated damages provisions are.

[53] This calculation assumes a 15 percent average capacity factor, which is conservative and likely to result in a lower implied energy rate for the winter period when the Facilities would not be expected to operate as much as in the summer peaking season.

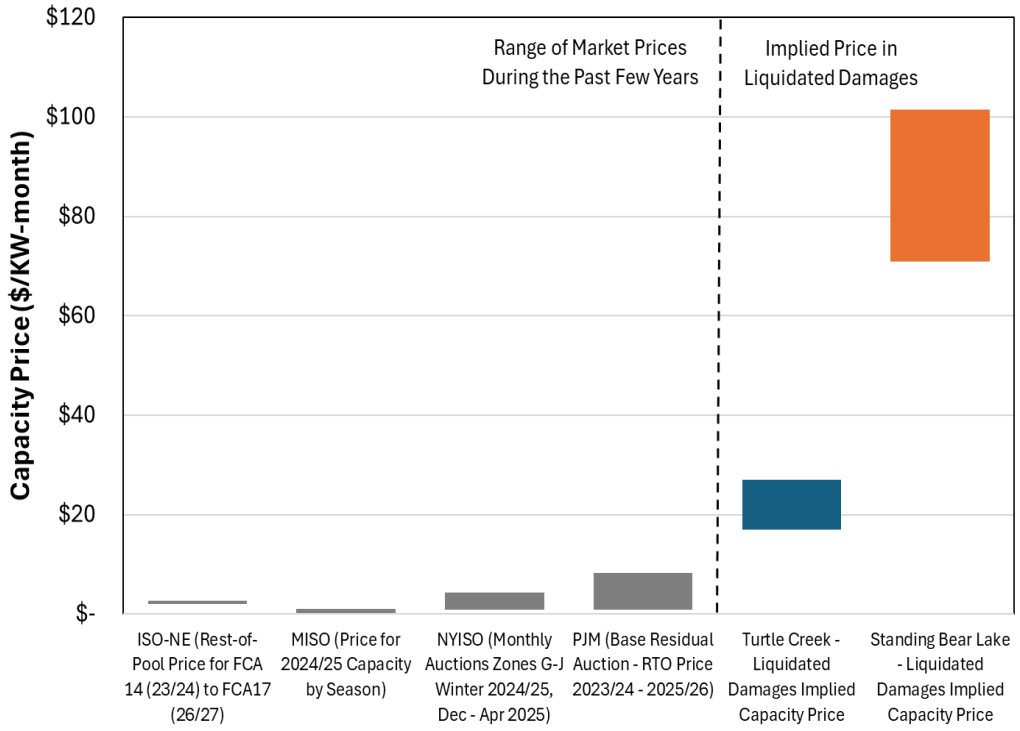
Figure 6: Implied Price for Energy in the Liquidated Damages Rate vs. SPP Prices



42. Similarly, the implied capacity price, assuming only value from capacity, is significantly higher than market indicators. Although SPP does not have a centralized capacity market with a transparent price for comparison, the capacity price in other markets is well below the implied price for capacity in the Liquidated Damages provision (**Figure 7**).[54]

[54] I understand from Counsel that OPPD has claimed to have entered into capacity contracts with third parties in anticipation of the delay. To the extent those bilateral contract details are provided, a more direct comparison could be made as to how the Liquidated Damages provisions compare to the costs estimated to be incurred by OPPD to replace the lost capacity of the Facilities. I understand, however, that OPPD has declined to provide information on transactions or prices paid to replace the power from the Facilities.

Figure 7: Implied Price for Capacity in the Liquidated Damages Rate vs. Other Markets[55]



43. These calculations of implied energy and capacity values are for illustrative purposes only. In fact, these units are expected to generate net revenues from three separate revenue streams: energy, capacity, and ancillary services. I calculate economic damages associated with each of these Electricity Products.

44. Based on my analyses of the Liquidated Damages provisions described in this section, I conclude the following:

1) **The Liquidated Damages provisions**, as constructed, do not reflect an estimate of economic harm. Amendment No. 1 increased the daily rate by $100,000 for the first month and thereafter for each of the Facilities. Amendment No. 2 increased the daily rate by another $100,000 to $200,000, depending on the Facility and whether it is applied to the first month or thereafter. There seems to be no underlying calculation to support these values, which also do not appear to be based on market conditions or economics.

2) **Amendment No. 2** significantly increased the daily delay charge for Liquidated Damages for delays extending from August to winter 2024/25, which is counter-

[55] Other markets that do have centralized procurement of capacity include New England ("ISO-NE"), New York ("NYISO"), and the Pennsylvania-Jersey-Maryland Interconnect ("PJM").

intuitive to the summer peaking nature of the SPP market, indicating a disconnect to OPPD's anticipated damages that is not reasonable.

3) **The implied energy and capacity prices** in the Liquidated Damages provisions are exorbitantly high compared to market prices for the same Electricity Products, indicating an unreasonable disconnect from the economic value of incurred due to the delay.

In other words, the Liquidated Damages daily charge, acceleration provisions after two months of delay, and implied values for energy and capacity indicate a complete disconnect from economic damages that OPPD could be expected to incur as a result of a delay in the Guaranteed Substantial Completion Date.

IV. Economic Damages

45. This section describes my calculation of estimated economic damages. The detailed calculations quantify the extreme disconnect between the Liquidated Damages provisions in Amendment No. 2 compared to the economic harm that OPPD may have incurred due to the delay in Substantial Completion. In my opinion, the disconnect is so large as to question whether Liquidated Damages in the Second Amended EPC contract was even intended to address economic harm in the first place.

46. I am informed by Counsel that, under Nebraska law, "the measure of damages for a breach of a contract claim is an amount that would place [the plaintiff] in as good a position as it would have enjoyed if the contract had been performed."[56]

47. The first question to ask is how OPPD was harmed. Presumably, in the absence of the Facilities, OPPD had to procure replacement power that otherwise would have been produced by the Facilities if the Guaranteed Substantial Completion Date had been achieved.[57] This is equivalent to calculating the replacement power costs to the operating costs that the Facilities would have incurred if the Guaranteed Substantial Completion Date

[56] *Infogroup, Inc. v. Database LLC*, 956 F.3d 1063, 1068 (8th Cir. 2020) (approving jury instruction so stating; citing *Bachman v. Easy Parking of America, Inc.*, 562 N.W.2d 369, 373 (Neb. 1997)).

[57] It is presumed that OPPD had to procure replacement power due to the delay in Substantial Completion. In fact, the Facilities were meant to replace existing units that OPPD intended to retire once the Facilities were operational. If the retirement of these units had been deferred due to the delay in Substantial Completion of the Facilities, economic damages would be lower than what I calculate – reflecting a combination of the costs of operating the old units and purchase replacement power to make up the difference. No additional capacity would need to be procured. The difference in ancillary services would be negligible. Therefore, my calculations of economic damages are a conservative measure of any potential harm that OPPD incurred due to the delay in Substantial Completion of the Facilities.

had been met. This approach can be positioned as an actual world versus a but-for world, a traditional methodology for calculating economic damages.[58]

- **Actual World:** Estimate of OPPD's actual purchase costs for Electricity Products; and
- **But-for World:** OPPD's estimated production costs to produce the Electricity Products had the Facilities been operational.

48. Under this methodology for calculating economic damages for breach of a contract claim, it is simple to assess economic damages as follows:

Economic Damages = Actual World less But-for World

= Higher Purchases Costs plus Lost Sales

= Higher Purchase Costs less Cost to Produce (Generate)

Specifically, economic damages effectively are the difference between the market price for the Electricity Products that the Facilities would have produced less the cost that would have been incurred if the Facilities had been operational (e.g., the cost of generation for energy).

49. Damages can be calculated as they actually occurred or as they were anticipated to occur:[59]

- **Ex-Post:** Calculating damages that actually did occur, using information known or knowable up to the issuance of the calculation, and updated at the time of judgment to reflect new information; or
- **Ex-Ante:** Calculating damages as of a historical point in time that reflects when the wrong-doing occurred.

[58] Among other references in Exhibit B, see for example:

Mark A. Allen, Robert E. Hall, and Vicotria A. Lazear, National Academies of Sciences, Engineering, and Medicine. 2011. Reference Manual on Scientific Evidence: Third Edition. Washington, DC: The National Academies Press. https://doi.org/10.17226/13163. "Reference Guide on Estimation of Economic Damages." National Academies of Sciences, Engineering, and Medicine. 2011. Reference Manual on Scientific Evidence: Third Edition. Washington, DC: The National Academies Press. https://doi.org/10.17226/13163.

[59] Among other references cited in Exhibit B, see for example:

Julie M. Carey, Christian Dippon, and Ralph Meghames, Global Arbitration Review, "Demystifying the damages assessment in international arbitration," June 21, 2024, https://globalarbitrationreview.com/guide/the-guide-damages-in-international-arbitration/6th-edition/article/demystifying-the-damages-assessment-in-international-arbitration

I have been asked by Counsel to calculate damages both ways, and to illustrate how a reasonable estimate of economic damages could have been performed as of the date Amendment No. 2 was signed (i.e., August 1, 2024).

50. The actual cost of OPPD's purchases of electricity to replace the Facilities is easily calculated from two simple inputs:

- **Quantity:** The amount of Electricity Products the Facilities would have produced; and
- **Price:** The market price for those Electricity Products.

51. The Quantity that the Facilities did not produce can be estimated using a simple spreadsheet model.

52. In calculating the actual cost of OPPD's purchases of replacement power, actual trade information from OPPD regarding its purchases and sales during the damages period could serve as the basis for damages. Such information would be particularly useful to the extent the incremental purchases or lost opportunities can be clearly delineated as being related to the failure to achieve Substantial Completion.

53. If OPPD entered into capacity contracts in anticipation of the delayed operations of the plants, the cost of such contracts could be considered in a damages calculation once they are provided. However, I have not yet been provided such information to incorporate into a calculation of economic damages that OPPD estimated to be incurred.[60] If such information becomes available, it can be incorporated into the damages calculation.

54. With respect to the market price, market information is readily available. In the absence of OPPD trade data, SPP prices can be used to estimate the value of the foregone Electricity Products. This information clearly would be in the possession of OPPD as an electric utility, generator, reliability planner, market participant in SPP, and LRE responsible for meeting its RAR. With that pricing data, combined with the estimated quantity that the Facilities would have produced, OPPD's actual cost to replace the Facilities due to the delay in Substantial Completion can be calculated using a simple spreadsheet model.

55. I therefore calculate damages as the difference between the market value of Electricity Products that the Facilities could have produced less the costs that OPPD would have incurred if the Facilities had been operational. This can be represented in an Actual/But-for World construct in one of two ways:

- **Lost Sales:**
  Actual World = Reduced or no sales due to delay
  But-for World = Net Revenues of sales that otherwise would have occurred

[60] I understand that Counsel has requested such data to be provided by OPPD on a voluntary basis.

- **Increased Purchase Costs:**
  Actual World = Purchases to cover lost services (e.g., replacement power costs)
  But-for World = Production costs that otherwise would have delivered the services

Although these can be mathematically equivalent, it is important to identify the construct that best reflects the cause of harm so that a make-whole calculation can be performed accurately.

56. Generally, the damages period reflects the period of time for which the Actual World diverges from the But-for World due to the wrong-doing for which defendant is liable. In this case, I do not tie the economic damages to any entities actions or liability. Instead, I calculate damages resulting from all delays, regardless of the cause or responsible party, to illustrate the difference between economic damages that may have been incurred by OPPD and Liquidated Damages. Once information is provided as to which entity caused which delays, liability for damages and an associated calculation can be performed.

57. Once the methodology is established, it is relatively simple to calculate damages using information that is readily available in the energy industry. Damages for a delay in Substantial Completion are readily ascertainable and capable of measurement. For example:

1) **Energy:** The harm is the inability of OPPD to generate and sell energy into the SPP market. Damages are the difference between Actual World of zero sales less the But-for World of net revenues associated with the market price for energy less the production costs for the energy that the Facilities would have produced.[61]

2) **Ancillary Services:** The harm is OPPD's inability to ancillary services into the SPP market. As with Energy, damages are the difference between the Actual World of zero sales less the But-for World of sales of ancillary services into the SPP market. [62]

3) **Capacity:** The harm is OPPD's higher purchase costs of capacity and/or reduced sales to third parties. Unlike energy and ancillary services, SPP does not operate a central market for capacity. Instead, entities such as OPPD who are responsible for ensuring sufficient capacity reserves are required to procure and build those reserves and report them to SPP through a submitted workbook to show sufficient capacity. I understand from Counsel that OPPD has claimed that it had to purchase capacity from third parties to meet its obligations. If so, damages are the difference between the Actual World of

[61] SPP settles generators separately from load. Therefore, the harm would be reduced sales of energy.

[62] SPP settles ancillary services providers separately from load. Therefore the harm would be reduced sales of ancillary services.

those purchases less the But-for World where no incremental capacity purchases were required because the Facilities met the Guaranteed Substantial Completion Date.[63]

58. These inputs to a calculation of economic damages are readily available or can be calculated from public data that SPP posts, as well as information reported to the U.S. Energy Information Administration. The amount that the Facilities would have produced can be estimated using a production cost model. I have performed these types of calculations multiple times in my career – usually in the context of estimating damages.

59. In addition, I expect that OPPD regularly reviews market price data to inform the trading activity in which it engages to procure the amounts of energy, ancillary services, and capacity to meet its load obligations. It is my opinion that the calculation I perform to assess the difference between market value and the value of the Facilities for purposes of economic damages is likely to be similar to the assessment that OPPD regularly performs as to whether to buy versus build new generation facilities.

60. If there are specific purchases and sales that OPPD entered into in anticipation of or because of the delayed Guaranteed Substantial Completion Date (i.e., to mitigate damages), I can incorporate those trades into the calculation once they become available. In the meantime, a calculation of economic damages using market prices provides a relevant indicator of how OPPD's actual damages compare to the Liquidated Damages calculation submitted by OPPD in its claim.

61. I summarize how economic damages can be calculated for each type of Electricity Product (i.e., energy, ancillary services, and capacity) below.

IV.A. Economic Damages from Delayed Energy Production

62. As already mentioned, OPPD expected the Facilities to be peaking units that would generate around 15 percent of the time. The energy that the Facilities produce is sold directly into the SPP spot market. OPPD purchases the energy that it requires to meet the needs of its customers directly from the SPP spot market. SPP settles for OPPD for generation and energy purchases.[64]

63. Economic damages are the net revenues that OPPD did not receive because the Facilities were not available to produce energy. The Actual World is zero sales for the delay period. The But-for World is the difference between the market price for energy and the costs that OPPD would have paid if the Facilities had been operational. To estimate economic

[63] To the extent SPP intended to retire older units once the Facilities achieved Substantial Completion, but delayed that retirement, damages could be mitigated. I do not consider this scenario in calculating damages even though it could would reduce them to the difference between the cost to produce at the old power plants versus the cost to produce at the Facilities.

[64] OPPD, Balancing supply and demand, June 11, 2024, https://oppdthewire.com/energy-marketers-balance-supply-and-demand/

damages associated with the lost energy generation due to the delay in Substantial Completion, key inputs to analysis include the following:

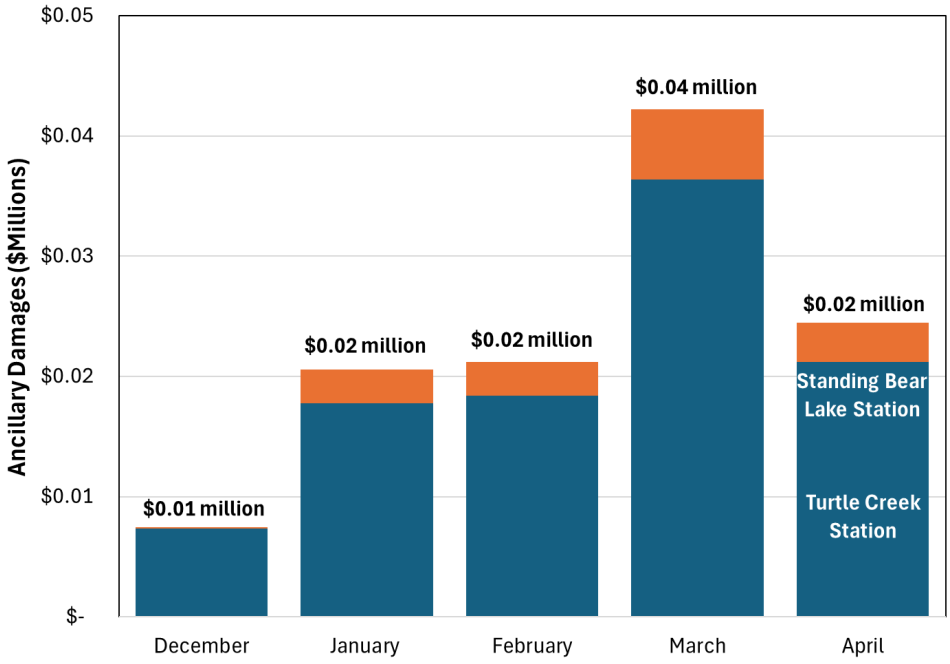
1) **Quantity:** The amount of energy that the Facilities would have generated based on SPP's economic dispatch of the Facilities (i.e., a comparison of production costs versus market prices);

2) **Price:** Market price for energy that the Facilities would have generated and that OPPD had to purchase because the Facilities did not; and

3) **Generation Costs:** Production costs associated with the generation of the quantity of energy that the Facilities would have produced.

64. A simple dispatch model combined with published data on SPP wholesale market prices for energy, natural gas prices and other variable costs of production, and an assumed conversion factor relating the amount of natural gas required to produce a megawatt-hour of energy can be used to estimate economic damages associated with any harm associated with delayed energy production from the Facilities (**Figure 8**).

Figure 8: Economic Damages from Delayed Energy Production



Gross Revenue	Cost of Production	Difference
$ 24,596,983	$ (17,019,898)	$ 7,577,085

IV.B. Economic Damages from Delayed Ancillary Services

65. The Facilities consist of fast-start and fast-ramp generation technologies that could provide a number of ancillary services to the SPP market.[65] Damages are equal to the lost net revenues from sales of ancillary services during the delay period. Actual World = No ancillary service from the Facilities; But-for World = Net revenues that the Facilities would have generated from supplying ancillary services

66. As a general rule, ancillary services are not a significant source of revenues for most generators. In SPP, the amount of ramp and spinning reserves is approximately equivalent to the capacity of the Facilities, on average. Yet, there is potentially 23,000 MW of simple cycle combustion turbines out of nearly 100,000 MW of total capacity that the Facilities would be competing against.

67. Although the Facilities may provide regulation services in the future as more renewable resources come online, they are not expected to have earned significant revenue from provision of such services this past winter and spring if they had been Substantially Complete.

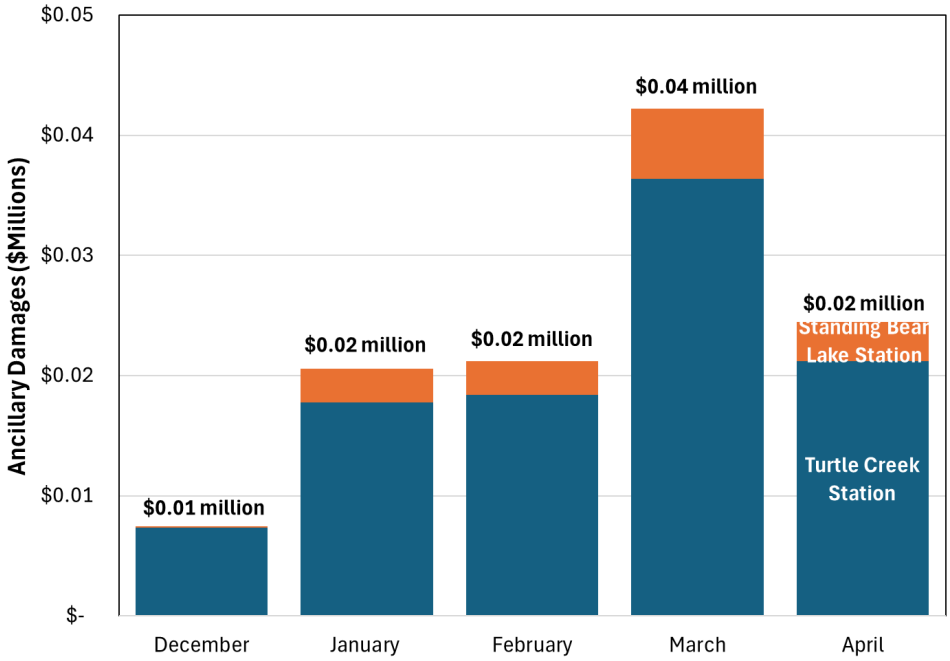
68. Ideally, I would be able to review the projections that OPPD performed to understand the anticipated net revenues for ancillary services that the Facilities were expected to generate. In the absence of that data, or the SPP settlements data for OPPD that would indicate how much its generation plants earn in from ancillary services, Instead, I apply hourly clearing prices for SPP Regulation-Down and Spinning Reserves to the capacity of the Facilities depending on whether they were dispatched (so could provide Regulation-Down) or not operating (and therefore could provide Spinning Reserves).[66] That said, as OPPD and SPP information becomes available, I reserve the right to modify this estimate.

69. As OPPD would not have sold a significant amount of Ancillary Services, harm associated with the delayed ability to generate Ancillary Services at the Facilities would be relatively small (**Figure 9**).

[65] WÄRTSILÄ, WÄRTSILÄ 50DF, https://www.wartsila.com/docs/default-source/energy-docs/technology-products/product-leaflets/wartsila-50df.pdf?sfvrsn=e9eda345_20; SIEMENS energy, SGT6-5000F gas turbine, https://www.siemens-energy.com/us/en/home/products-services/product/sgt6-5000f.html#accordion-f77d3baa53-item-90e17cc04b

[66] Given that the dispatch model assumes that the Facilities are either operating at full capacity or not at all, we do not incorporate potential ramping services. Again, given the competition, potential revenues from such services are likely to be negligible.

Figure 9: Economic Damages from Delayed Ancillary Services



IV.C. Economic Damages from Delayed Capacity

70. Under the SPP Market Rules and Open Access Transmission Tariff, all reserve planners (such as OPPD) are required to have a sufficient amount of resources to meet its peak load requirements plus a reserve above and beyond the peak.

71. Unlike other markets, SPP does not operate a centralized market for capacity. However, market participants who are short can purchase capacity from third parties and those who are long can sell capacity through bilateral arrangements. Such transactions would be available in OPPD's workbook submitted to SPP to confirm that it had sufficient capacity resources.[67]

72. In the absence of access to OPPD's tradebook, capacity value can be estimated using SPP estimates of its reserves and a nearby market price for capacity.

73. SPP has excess reserves for winter 2024/25.[68] Therefore, I would expect the price for capacity to be less than the Net Cost of New Entry ("Net CONE"). Multiple ISOs project the Net CONE (i.e., CONE less net revenues from energy and ancillary services) as part of

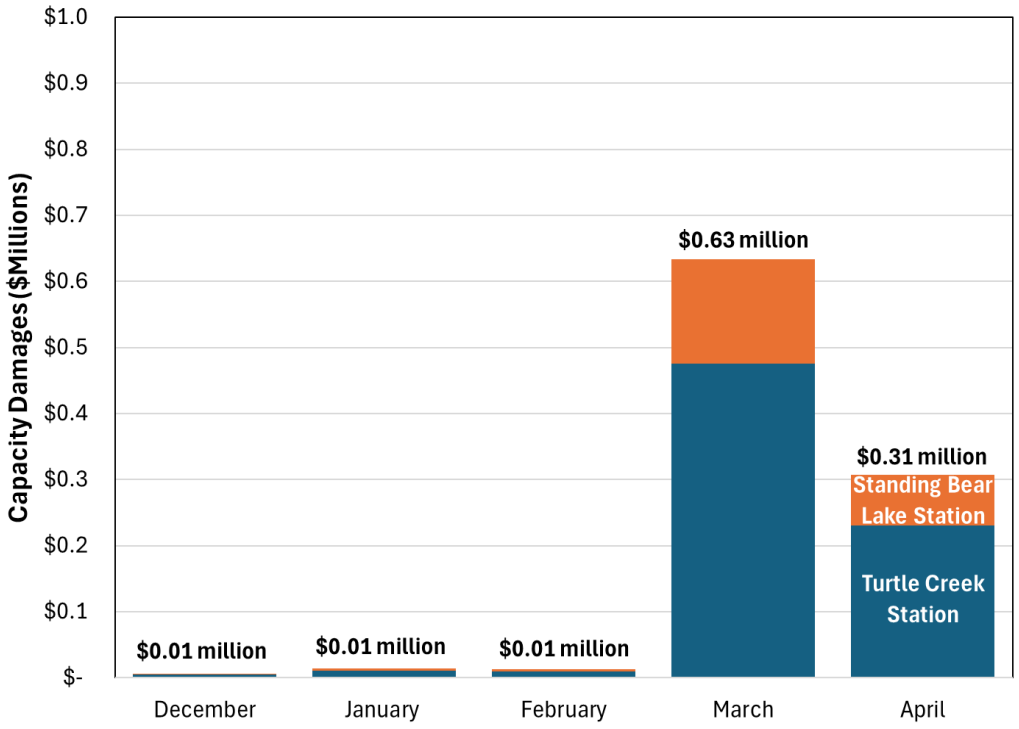
[67] SPP, OATT, Attachment AA Resource Adequacy, Section 13 and Section 14, https://spp.org/documents/58597/attachment%20aa%20tariff.pdf

[68] NERC, "2024-2025 Winter Reliability Assessment," November 2024, p, 18, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf

their capacity market parameters. SPP also projects CONE as part of its penalties for deficiencies in reserves.[69].

74. The price for capacity in the neighboring market operated by MISO provides proxy prices for what OPPD may have had to procure to cover the delayed capacity from the Facilities. Multiplying the Capacity Prices for Iowa, which is contiguous to Nebraska and interconnected to the OPPD system, estimates damages associated with capacity that OPPD may have had to procure as a result of the delay in the Substantial Completion of the Facilities. Under this approach, damages caused by the delay in capacity is estimated to be less than $1 million (**Figure 10**).

Figure 10: Economic Damages from Delayed Capacity



75. Unlike with energy, there is no production cost for capacity. I am informed that OPPD already has paid against the milestones in the Second Amended EPC Contract. Therefore, the costs to produce are fixed in both the Actual and But-for Worlds and cancel out.

[69] SPP OATT § 13.0.

IV.D. Conclusions on Economic Damages

76. The calculation of economic damages is not complex and can be calculated using a standard spreadsheet software such as Excel.

77. **Figure 11** summarizes the economic damages estimated to be incurred by OPPD due to the delayed Guaranteed Substantial Completion Date for the period December 17, 2024 through April 15, 2025.

Figure 11: Estimated Economic Damages (December 17, 2024 through April 15, 2025)[70]

Damages Category	Standing Bear Lake	Turtle Creek	Total
Energy	$1,955,162	$5,621,923	$7,577,085
Ancillary Services	$ 14,781	$ 101,150	$ 115,931
Capacity	$ 242,040	$ 730,845	$ 972,885
TOTAL	**$2,211,983**	**$6,453,918**	**$8,665,901**

This is the equivalent to OPPD having to purchase $25.7 million dollars in energy, capacity and ancillary services, and incurring the production costs of $17.0 million.

Damages = Higher Purchase Costs less Cost to Produce (Generate)

= $25.7 million - $17.0 million

= $8.7 million

78. The reasonableness of these values can be confirmed by comparison to the MISO calculation of the Cost of New Entry ("CONE") less projected net revenues for energy and ancillary services (i.e., the Net CONE). for purpose of setting parameters in its centralized capacity market. MISO projects the CONE in the MISO North/Central region which is interconnected to SPP near OPPD to be $121,220/MW-year for 2025/26 and the Net-CONE to be $73,636 / MW-year.[71] The difference represents expected net revenues from energy and ancillary services. Multiplying times the 600 MW the Facilities represent totals annual revenues for these two Electricity Products equal to $28.6 million for the year (or $9.5 million for four months).[72] This pro-rata value, which does not account for seasonality

[70] The Guaranteed Substantial Completion Date for Turtle Creek Station is December 16, 2024 and for Standing Bear Lake Station, December 30, 2024. Damages begin the following day.

[71] MISO, Resource Adequacy Subcommittee (RASC), "MISO Cost of New Entry (CONE) and Net CONE Calculation for Planning Year 2025/26," September 23, 2024, p. 18, https://cdn.misoenergy.org/20240923%20RASC%20Item%2003%20CONE%20and%20Net%20CONE%20Update649247.pdf

[72] This pro-rata share assumes that net revenues are distributed equally across the months. In fact, the Facilities would

and therefore would overstate winter damages, is extremely close to the sum of damages for energy and ancillary services of $7.7 million that I estimate. Perhaps more importantly, the MISO calculation of Net CONE for 2025/26 confirms:

- **Damages calculations are straightforward:** Calculating damages incurred by OPPD due to delay of Substantial Completion is not complex.

- **Electricity industry entities frequently perform forward-looking estimates:** MISO performs such projections, along with other ISOs, investors, and market participants.

- **The annual value of projected net revenues from energy and ancillary services for a new combustion turbine such as Turtle Creek is significantly below the Liquidated Damages provisions.** MISO assumes that an advanced combustion turbine is the next new entrant. MISO calculates the all-in total cost of such a new entrant through the CONE, and the required capacity costs once net revenues from energy and ancillary services are considered through the Net CONE. SPP and MISO currently have excess capacity, so the value of such capacity during the delay is well below the estimated cost required to support a new entrant. The difference between CONE and Net CONE (representing the value of energy and ancillary services in the MISO market) is well below Liquidated Damages, and the low capacity value indicated by MISO's centralized capacity auctions do not make up the difference.

- **The reasonableness of my economic damages calculations are confirmed.** The MISO's CONE and Net CONE values confirm that my calculations of economic damages for energy and ancillary services are an accurate representation of the relative magnitude of actual and projected damages compared to the Liquidated Damages value.

79. SPP also calculates CONE as part of its methodology for assessing penalties on market participants for failure to maintain sufficient RAR.[73] In SPP's Open Access Transmission Tariff ("OATT") Section 13.0, SPP states, "The Cost of New Entry ("CONE") value shall be 85.61 $/kw-yr." Multiplying this value by 600 MW (i.e., 600,000 kW) results in a total value of $51.4 million.[74] In other words, Liquidated Damages exceed the CONE of a new entrant of the same size as the Facilities. Once again, the Liquidated Damages values are unreasonable and completely disconnected from the economics of new power plants.

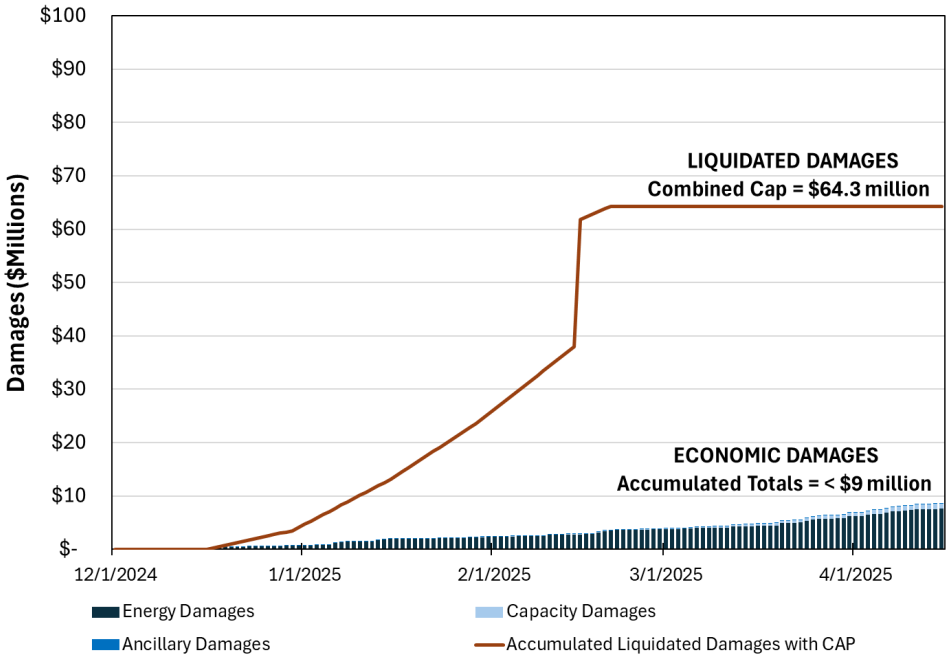
be expected to produce more in the summer months, explaining why the economic damages calculation would be less than the pro-rata share.

[73] SPP Open Access Transmission Tariff, Section 13.0 and 14.2, https://sppviewer.etariff.biz/tariff

[74] Calculation: 600,000 kW x $85.61 / kW-year = $51,366,000.

80. Plotting the underlying detail to the total ex-post economic damages calculation to cumulative Liquidated Damages illustrates the magnitude of the disconnect between the two (**Figure 12**).

Figure 12: Cumulative Economic Damages versus Liquidated Damages



81. The approach I describe above is used by the industry to determine damages for project delays, cancellations, and failure to deliver guaranteed quantities. The attached Exhibits provide additional detail as follows:

- **Methodology:** Exhibit D provides a more detailed description of the methodology used to estimate damages.

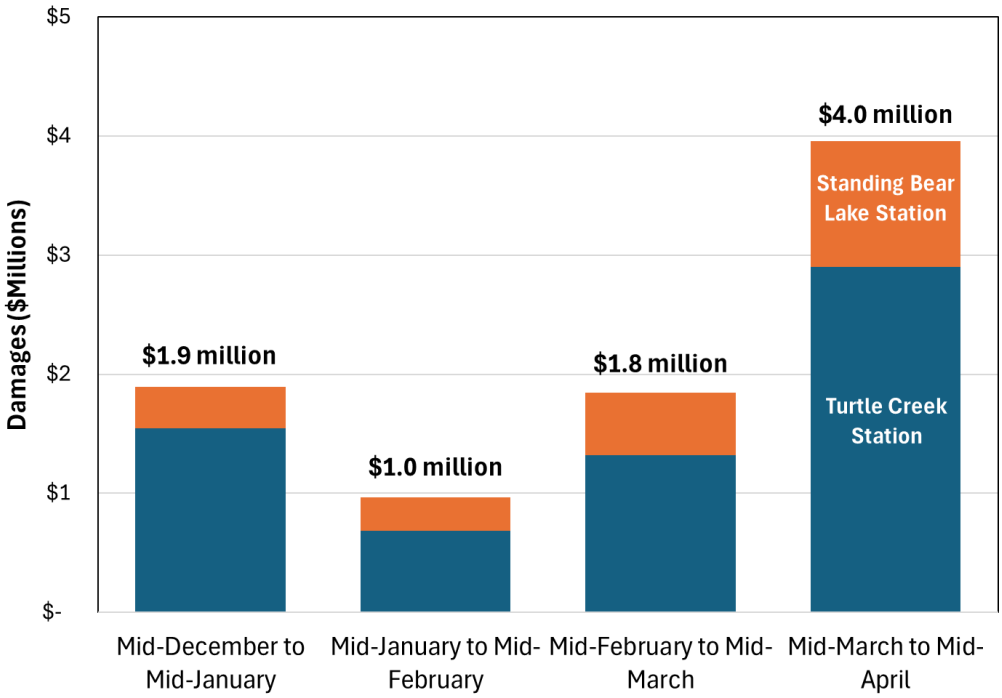
- **Assumptions:** Exhibit E provides a more detailed description of the data sources and inputs used in the calculation of economic damages.

82. I understand that the Guaranteed Substantial Completion Date is imminent. I calculate the economic damages starting the day after the Guaranteed Substantial Completion Date in the Second Amended EPC Contract using historical data. If needed for an economic damages calculation, this can be extended to a future date to include the entirety of a damages period. In the meantime, this value through mid-April serves to illustrate the extreme discrepancy between Liquidated Damages versus the economic damages that OPPD incurred.

83. Economic damages estimated to have been incurred by OPPD for the period through April 15, 2025 are around $8.7 million. This value is well below the Liquidated Damages Provisions.

84. The distribution of economic damages over time illustrates the summer peaking nature of the Facilities. Except during a winter storm or extreme weather event, the Facilities are not expected to operate much during the winter and spring seasons. Economic damages are higher this past spring due to an extreme weather event[75] (**Figure 13**).

Figure 13: Estimated Economic Damages by Month



85. In conclusion, the amount specified for liquidated damages in Amendment No. 2 is vastly greater than OPPD's economic damages incurred during the period from December 17, 2024 through April 15, 2025. For this period, Liquidated Damages are over 7 times greater than the economic damages that OPPD is estimated to have incurred. The Liquidated

[75] According to the National Weather Service, "A strong, early spring low pressure system tracked from the central Plains through the Upper Midwest Wednesday, March 19th bringing blizzard conditions across Nebraska and Iowa, blowing dust and wildfires across the southern Plains, and severe thunderstorms and tornadoes across Illinois and Indiana." National Weather Service, "March 19, 2025: Line of Storms Produces Damaging Winds, Hail, and Multiple Tornadoes," March 19. 2025, https://www.weather.gov/lot/2025_03_19_SevereWeather#:~:text=A%20strong%2C%20early%20spring%20low%20pressure%20system%20tracked,severe%20thunderstorms%20and%20tornadoes%20across%20Illinois%20and%20Indiana.

Damages Provisions in Amendment No. 2 do not provide a reasonable estimate of harm incurred by delay in Substantial Completion of the facilities.

86. I also conclude that actual historical data is readily available to perform a calculation of economic damages that had been incurred by OPPD due to a delayed Guaranteed Substantial Completion Date. Furthermore, OPPD would have had more detailed information regarding the trades and contracts, if any, that had been entered into to mitigate damages. Such trades can be incorporated into the estimated damages calculation when made available.

V. Anticipated Damages as of August 1, 2024

87. This section addresses whether OPPD would have been able to anticipate the economic damages that would have been incurred due to a delay in the Guaranteed Substantial Completion Date. In my experience, these types of "ex-ante" calculations are performed all the time by industry investors and market participants.

88. In my opinion, OPPD would be able to estimate potential economic damages using market information available on a day-to-day basis. Specifically, market participants would have access to:

1) **Price:** Recent settlements and futures prices for Electricity Products that the Facility were expected to produce, include the following:

    a. **SPP Futures Prices for Energy Shaped by Historical Conditions:** Market-based forward trades and futures prices for natural gas at a nearby hub and energy in SPP North, the zone in which the Facilities would be operating and into which OPPD would deliver its energy from the Facilities, plus a five-year history of hourly pricing for five different price shape scenarios;

    b. **SPP Market Prices for Ancillary Services:** Recent and anticipated prices (based on futures energy prices) for Ancillary Services that the Facilities would have produced or that OPPD may have purchased in the absence of the Facilities, and an interim estimate of damages associated with the delayed sales of ancillary services; and

    c. **Bilateral Market Prices for Capacity:** Prices for capacity established in the MISO market for Iowa that OPPD procured or would have been able to sell if the Facilities had been operational.

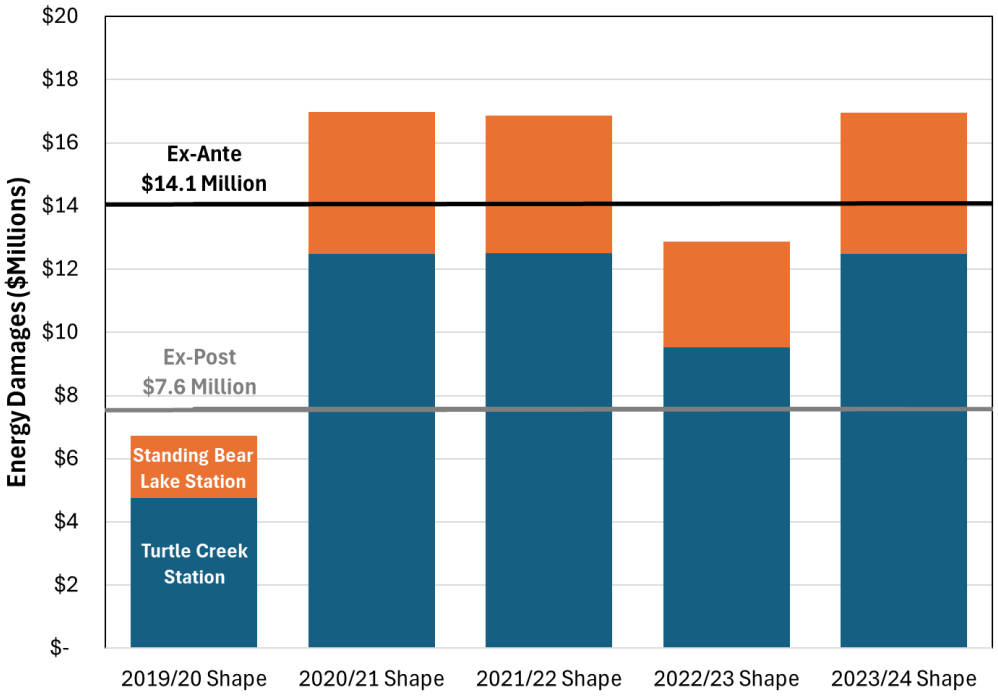
2) **Quantity:** The quantity that each Facility would have produced can be estimated using the same approach described for historical data, but applied to the new price projections.

In other words, the data and methodology exist to project expected damages the event of a delayed start date.

89. I use this approach to estimate what OPPD could have projected damages to be as of August 1, 2024, the date when Amendment No. 2 was signed.

90. Using information known or knowable as of August 1, 2024, and the methodology described above, I estimate that projected economic damages for energy during the period from December 17 through April 15, 2025 would have been $6.7 million to $17.0 million, depending on the assumed price shapes, with an average of the past five years totaling $14.1 million (**Figure 14**). This range is consistent with the economic damages I calculated using historical data.[76]

Figure 14: Ex-Ante Energy Damages due to Delayed Energy as of August 1, 2024



91. Prices for capacity and ancillary services are less volatile than energy prices, and therefore less complicated to estimate. MISO capacity markets had established the forward-looking

[76] For context, recall that the past four years have experienced extremely disruptive events which would be expected to result in higher damages value, including: 1) A world-wide pandemic starting in 2020; 2) Winter Storm Uri in 2021; 3) extremely high global natural gas prices due to the Russian invasion of the Ukraine in 2022; and 4) supply chain issues and inflation in 2023, that carried forward into 2024.

price during its auctions held on March 26, 2024. I therefore use the same prices for capacity in the ex-ante analysis as for the ex-post analysis.

92. SPP ancillary services auctions are held on a day-ahead and real-time basis. SPP has established a methodology for estimating future ancillary services that a new entrant would receive. As part of the Net CONE calculation used to apply penalties to market participants that fail to meet their RAR, SPP calculates a standard deficiency payment based on a calculated "Sufficiency Valuation Curve."[77] The Sufficiency Valuation Curve is based on the cost of new entry ("CONE"). I apply the pricing from the prior year's auctions to estimate economic damages on an ex-ante basis as of August 1, 2024, and actual ancillary services prices for the ex-post damages assessment.

93. The projected range for economic damages using an ex-ante approach is significantly below the value generated by the Liquidated Damages provisions for that same period (**Figure 15**).

Figure 15: Ex-ante Damages by Electricity Product (December 17, 2024 – April 15, 2025[78]

Damages Category	Standing Bear Lake	Turtle Creek	Total
Energy	$3,728,946	$10,350,734	$14,079,680
Ancillary Services	$ 15,871	$ 108,361	$ 124,232
Capacity	$ 242,040	$ 730,845	$ 972,885
TOTAL	**$3,986,857**	**$11,189,940**	**$15,176,797**

94. In my opinion, I conclude that OPPD could have projected anticipated economic damages as of August 1, 2024 or could have included language describing how to calculate such economic damages in a Liquidated Damages provision either on an ex-post or ex-ante basis.

VI. Conclusions

[77] In 2023, SPP filed to request approval to assess penalties against market participants that did not have sufficient capacity to meet their RAR during the winter months of December 1 to March 1. Although this was rejected by FERC, the FERC Order provides an overview of SPP's use of CONE and Net CONE in the context of capacity and how market participants such as OPPD may procure such capacity. 185 FERC ¶ 61,159 UNITED STATES OF AMERICA FEDERAL ENERGY REGULATORY COMMISSION Before Commissioners: Willie L. Phillips, Acting Chairman; Allison Clements, and Mark C. Christie. Southwest Power Pool, Inc. Docket No. ER23-2781-000 ORDER REJECTING TARIFF REVISIONS (Issued November 30, 2023), https://www.spp.org/documents/70636/20231130_order%20rejecting%20tariff%20revisions%20-%20revisions%20to%20add%20winter%20season%20resource%20adequacy%20requirement_er23-2781-000.pdf

[78] Other markets that do have centralized procurement of capacity include New England ("ISO-NE"), New York ("NYISO"), and the Pennsylvania-Jersey-Maryland Interconnect ("PJM").

95. Economic damage estimates actually incurred by OPPD can be readily calculated using publicly-available information.

96. Based on my calculations, OPPD incurred economic damages at levels significantly lower than what the Liquidated Damages provisions are for the delay in Substantial Completion through April 15, 2025.

97. The same methodology could be applied looking forward at an historical date to project expected economic damages.

98. Per the request of counsel, I project what such an estimate of future economic damages would be as of August 1, 2024, when Amendment No. 2 was signed, and conclude that (i) OPPD could have performed such a calculation with information known or knowable on a forward-looking basis; and (ii) the values would have been significantly lower than the daily delay charge in the renegotiated Liquidated Damages provisions in Amendment No. 2.

I declare under penalty of perjury under the laws of the United States of America that the foregoing facts and data stated herein are true and correct. Executed on April 28, 2025.



Tanya Bodell

EXHIBIT A: Curricula Vitae



Tanya Bodell

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Partner

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Tanya Bodell, Partner, leads StoneTurn's energy and sustainability offerings in business advisory services, regulatory support, and expert testimony in large-stakes litigation, levering more than 25 years of experience in energy industry matters and associated environmental impacts.

Tanya provides business advisory and expert support to clients, advising on business strategy, asset valuations, mergers/acquisitions, market rules, regulatory outreach, and energy transition. She also provides expert testimony in solvency, regulatory and litigation cases pertaining to the energy industry, including damages claimed for breach of contract, fraudulent misrepresentation, market manipulation and other liability.

SELECT PROFESSIONAL EXPERIENCE

LITIGATION/REGULATION

Tanya has significant experience in high-stakes litigation in which hundreds of millions of dollars are at risk. She has played a key role in cases arbitrated, mediated, litigated, and heard before regulatory agencies, providing litigation support including assessment of business damages and lost profits, market context, expert testimony, economic arguments in legal filings, and settlements. From 2008 to 2011, she served a three-year term as Vice Chair of Standing Committee for the International Centre for Expertise at the International Chamber of Commerce. Below are selected examples of cases in which she has provided expert support and testimony.

Education

MBA, Sloan Fellow, Massachusetts Institute of Technology

MPP, Harris School of Public Policy, University of Chicago

B.A., Mathematical Economics, Pomona College

Practice Areas

Energy

Valuation

Litigation

Regulatory

Languages

English

Spanish

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Contract Dispute

- Provided industry context for contract interpretation regarding what would be considered comparable electricity products.
- In a dispute between two large hydroelectric power producers, served as the testifying expert on industry context pertaining to firm and non-firm electricity products.
- Served as the expert witness on industry context in a contract interpretation case between an electric cooperative and municipal electric company who jointly held rights to the output of a large coal generation plant.
- For various industry clients, reviewed multiple power purchase agreements to advise on contract renegotiations, merchant plant investment opportunities and valuation of non-utility generation acquisitions.
- For a waste coal facility in Pennsylvania, served as the independent appraiser of the facility to assess the fair market sales value under the remainder of the power purchase agreement and as a merchant plant.
- For a coal plant in Connecticut undergoing contractual restructuring, assessed the value of the facility under the existing power purchase agreement, a proposed tolling agreement, and as a merchant facility.
- For the counterparty to a long-term power purchase agreement with the California Department of Water and Power, reviewed publicly-available contracts and settlements to advise on potential contract restructuring positions.
- For a potential purchaser of a cogeneration project in Oklahoma, performed a market study to assess the regulatory regime and other aspects of the market that could affect the value of the investment, including future gas and electricity price projections.
- For an owner of a cogeneration project in Michigan, analyzed a proposed back-to-back transaction involving the power purchaser and a third party to determine whether the proposed agreement posed additional risks for the project. The analysis included review of the purchaser's stranded cost calculations and regulatory filings, as well as a detailed assessment of the two contracts and associated project documents.
- For a Maryland utility, calculated stranded costs associated with its power purchase agreement and determined potential settlement negotiation positions and strategies that the utility could take with respect to buying down the contract.
- For a Texas cooperative in a power purchase agreement with a cogeneration project, analyzed potential renegotiation positions, including the potential for a buy-out and buy-down of power prices.
- In a dispute over interpretation of the terms of a cogeneration contract in Florida, supported expert testimony on the application of the Public Utility Regulatory Policy Act (PURPA) to the contract. The analysis included a survey of all publicly available non-utility generation project contracts.

Damages

- Calculated damages related to cancellation of a solar energy project power purchase agreement in ERCOT.
- For a trading company, calculated damages associated with lost opportunity and out-of-pocket costs related to trading activities in exceedance of company credit limits and practices in MISO and ERCOT,

- For a California renewable power generator, calculated damages associated with the California fires and failure to be able to deliver electricity products to market and under contract.
- For a transmission owner being sued for failure to operate in accordance with standard utility practice, critiqued the plaintiff's expert analysis and performed a damages calculation of the opportunity cost of lost sales associated with the transmission line outage under prices that would have occurred if the plant had been operating.
- In a lawsuit between an electric utility and a cooperative that served multiple load serving entities, assessed the value of the excess energy the utility supplied to the load serving entities due to their breach of the supply contract.
- In a dispute between a large hydroelectric power producer and natural gas independent power producer in the Pacific Northwest over damages exceeding $1 billion, reproduced the independent power project's pro-forma and calculated lost profits to the project under various scenarios including alternative electricity and gas prices and water conditions. Developed the analysis of the required return on equity for highly leveraged non-utility generation projects, including the equity, debt, and financial Betas.
- In a dispute over interpretation of the terms of a power purchase agreement in New Jersey, calculated lost profits under alternative interpretations.
- In a contractual dispute between a U.S. electric utility and qualifying facility in Pennsylvania, analyzed the financial viability of the cogeneration project for a temporary restraining order proceeding, supported the expert testimony of the damages expert and assisted counsel for deposition and cross-examination questions.
- For an electric utility suing contractor for over $55 million over failure to install a fire protection, calculated impact on business due to replacement power costs incurred while the coal plant was down, a key aspect of the damages claim. Coordinated with other experts on related matters including project schedule and appraisal.
- For multiple litigations concerning Westinghouse nuclear steam generator product liability cases in which damages claims exceeded $500 million per case, developed damages approach and calculated alternative damages tied to liability case. Repeated and adjusted analytical approach for four of the ten lawsuits brought against Westinghouse by electric utilities, drafted expert reports, provided document review and deposition questions to counsel, and advised on strengths and weaknesses of case using ex-ante and ex-post approaches.

Tax Litigation

- In a claim concerning proper tax treatment of a contingent debt instrument, defended client against IRS investigation. Analyzed contingent debt instruments in the context of a 20-year, multi-billion dollar coal purchase agreement, drafted expert reports, and advised counsel on depositions.
- In an IRS claim concerning excessive retention of earnings by a privately-held marine transportation business, analyzed working capital and investment cash needs to show that the retained earnings were required to meet legitimate business purposes.

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EXPERT TESTIMONY

Tanya has testified on a number of matters in the energy industry, focusing on economic analyses, cost-benefit analyses, estimations of damages, and regulatory proceedings.

Litigation

- In the matter of the Brigham and Women's Hospital, Inc., Plaintiff, v. MATEP LLC, MATEP LP, and Longwood Energy Partners LLC, Defendants, before the Superior Court of the Commonwealth of Massachusetts, Suffolk, Civil Action No. 2384-CV-01373BLS2.
  - "Expert Report of Tanya L. Bodell on behalf of Defendants," November 7, 2024.
  - "Rebuttal Report of Tanya L. Bodell on behalf of Defendants," December 13, 2024.
- In the matter of City of Denton, Texas, acting by and through its Electric Utility Department Denton Municipal Electric v. Delilah Solar Energy LLC, Samson Solar Energy LLC, and Invenergy LLC, before the District Court, 192nd Judicial District, Dallas County, Texas, Case No. DC-22-17013:
  - "Expert Report of Tanya Bodell," August 26, 2024.
  - "Rebuttal Report of Tanya Bodell," October 25, 2024.
- In the matter of J. Christian Allen, an Individual, v. Concord Energy Holdings, LLC and Concord Energy, LLC, before the District Court in Denver County, Colorado, Case No. 2021CV32298, "Expert Report of Tanya L. Bodell," on market conditions and damages, October 23, 2023.
- American Arbitration Association, Dominion Nuclear Connecticut, Inc. vs. The Connecticut Light and Power Company, Case No. 01-16-0000-6412, "Prepared Direct Testimony of Tanya Bodell on Behalf of the Connecticut Light and Power Company," on damages, August 17, 2017.
- In the Matter of Hydro-Québec v. Churchill Falls (Labrador) Corporation Limited, Province of Québec, District of Montréal, Superior Court, N: 500-17-078217-133.
  - "Continuous Energy: An Overview of Contemporaneous Industry Context," July 10, 2015.
  - "Interruptible Power: An Overview of Industry Context and CF(L)Co's Ability to Sell," July 3, 2015.
- "Expert Report of Tanya L. Bodell," In the Matter of Arbitration Between Big Rivers Electric and City of Henderson Utility Commission d/b/a Henderson Municipal Power and Light, Defendants, American Arbitration Association Re: 52-198-00173-10, August 24, 2011.

Regulatory

- On behalf of the PJM Power Providers Group, Before the Federal Regulatory Committee, PJM Quadrennial Review, regarding proposed changes to the market rules for the Reliability Pricing Model market design:
  - "Affidavit of Tanya L. Bodell," Docket No. ER22-2984-000, October 21, 2022.
  - "Reply Affidavit of Tanya L. Bodell," Docket No. ER22-2984-000, November 14, 2022.

- On behalf of Kern Oil, prepared an economic report to evaluate claims made by Environmental Protection Agency in its December 7, 2021 Proposed Denial of Petitions for Small Refinery Exemptions related to the implications of Renewable Fuel Standard ("RFS") compliance requirements on a small refinery operating in central California titled, "Financial and Market Assessment of Renewable Fuel Standard Requirements on Kern Oil & Refining Company (EPA ID #5038)," 7 February 2022.
- On behalf of Morongo Transmission LLC, submitted expert testimony to FERC regarding the differential risks of their share of a transmission project over existing rights of way in Southern California compared to the risk of the partnering utility in support of transmission return on equity adders, Federal Energy Regulatory Commission, Docket No. ER21-669-000, "Prepared Direct Testimony of Tanya L. Bodell," December 15, 2020.
- On behalf of NRG Power Marketing, LLC, submitted expert testimony to FERC regarding the ISO-NE proposal to provide interim compensation for generation resources with inventoried fuel, Federal Energy Regulatory Commission, Docket No. ER19-1428-000, "Prepared Direct Testimony of Tanya L. Bodell," April 15, 2019.
- Prepared in Support of Comments filed on the Draft Environmental Impact Statement for the Coastal Plain Oil and Gas Leasing Program, 83 Fed. Reg. 67337 (Dec. 28, 2018) by the Attorneys General of States of Washington, Delaware, Oregon, Maine, Maryland, Michigan, Minnesota, New Jersey, New York, North Carolina, Rhode Island, Vermont, the Commonwealths of Massachusetts, Pennsylvania, and Virginia, and the District of Columbia, "Economic Assessment of Proposed Oil and Gas Lease Sales In the Arctic National Wildlife Refuge Coastal Plain," March 2019.
- On behalf of Calpine Corporation Vista Energy Corporation and Bucksport Generation, LLC (the Generator Intervenors) before the Maine Public Utility Commission, Docket No. 2017-00232.
    - "Prepared Direct Testimony of Tanya L. Bodell," submitted April 3, 2018.
    - "Prepared Surrebuttal Testimony of Tanya L. Bodell," submitted August 17, 2018.
    - "Prepared Corrected Supplemental Testimony of William S. Fowler and Tanya L. Bodell," Submitted December 24, 2018.
- Prepared Remarks of Tanya L. Bodell regarding Proposed Support for New Jersey Nuclear Plants before the New Jersey Senate Environment and Energy and the Assembly Telecommunications and Utilities Committee, State House Annex, December 20, 2017.
- On behalf of the PJM Power Providers Group, Before the Federal Regulatory Committee, PJM Quadrennial Review, "Affidavit of Tanya L. Bodell," Docket No. ER19-105-000.
- On behalf of the New England Power Generators Association, Exhibit NPG-4, Before the Federal Energy Regulatory Committee, Docket No. ER17-795-000.
    - "Prepared Direct Testimony of Tanya L. Bodell," submitted February 3, 2017.
    - "Prepared Surrebuttal Testimony of Tanya L. Bodell," submitted March 6, 2017.
- Massachusetts Electric Company and Nantucket Electric Company each D/B/A National Grid, before the Massachusetts Department of Public Utilities, Docket No. 1605.
    - "Testimony of Tanya Bodell on Behalf of the Massachusetts Attorney General," June 20, 2016.
    - "Surrebuttal Testimony of Tanya Bodell on Behalf of the Massachusetts Attorney General," July 18, 2016.

- NSTAR Electric Company and Western Massachusetts Electric Company D/B/A Eversource Energy, before the Massachusetts Department of Public Utilities, Docket No. 15-181.
  - "Testimony of Tanya Bodell on Behalf of the Massachusetts Attorney General," June 13, 2016.
  - "Surrebuttal Testimony of Tanya Bodell on Behalf of the Massachusetts Attorney General," July 12, 2016.
- Benefits analysis of the Towantic Energy Center, Testimony before the Connecticut Siting Council, Docket No. 192: An Application by Towantic Energy, LLC For a Certificate of Environmental Compatibility and Public Need for the Construction, Maintenance and Operation of a Proposed Electric Generating Facility Located North of the Prokop Road and Towantic Hill Road Intersection in the Town of Oxford, Connecticut Petition of CPV Towantic, LCC (f.k.a. Towantic Energy, LLC) to Reopen and Modify the Decision in Docket No. 192 Due to Changed Conditions. Report submitted October 2014 in conjunction with Concentric Energy Advisors, Inc.
- "Analysis and Cost Comparison of Renewable Power in California," Testimony before the Little Hoover Commission, Sacramento, CA, February 28, 2012.
- "Prepared Direct Testimony of Tanya L. Bodell on Behalf of Atlantic Path 15, LLC," Before the Federal Energy Regulatory Commission, Atlantic Path 15, LLC, Docket No. ER11-2909-000, submitted February 18, 2011.

ADVISORY SERVICES

Tanya interacts directly with executives, corporate boards, investors and senior management of energy companies, adding value through business strategy, market assessments, transaction support, valuations, and regulatory policy. Selected services and assignments cover all facets of the power sector, including renewables and energy storage, as well as aspects of the natural gas, liquified natural gas, coal, and oil sectors.

Business Strategy

For energy technology start-ups and established energy companies, Tanya develops strategy for expansion into new businesses, technologies and market segments, including advice on the regulatory structures, government support and entry strategies for investments in commercial transmission, energy storage solutions and renewable resources. Her advisory services focus on new entry strategy and commercialization, market assessments, target identification, strategic partners, mergers/acquisitions, and timing/type of potential exits under alternative commercialization strategies. Specific technologies for which Tanya has provided strategic advice include:

- **Renewable Generation:** For international companies focused on wind and solar technologies, Tanya has assisted with education, entry strategy, regional assessments, and identification of merger/acquisition targets to facilitate entry into U.S. markets.
- **Energy Storage:** For a number of energy storage technology start-ups, Tanya has served as an advisor, assisting with market valuations, cost-benefit analyses, target markets and entry strategy. The energy storage technologies that she has advised include long-duration thermal storage, battery energy storage systems, hydroelectric pumped storage, waste-to-energy systems, and hydrogen.

- **Transmission and Smart Grid Technology**: For transmission technology companies, independent transmission developers, and transmission enablers, she has identified potential investment opportunities, pathways to commercialization, and new entrant opportunities.
- **Microgrids**: Tanya has worked with technology providers and the utilities to develop potential microgrids to improve reliability and resiliency.
- **Hydrogen**: Tanya has served as an advisor for a new hydrogen fuel producer, assisting them with understanding U.S. power sector and natural gas markets to develop an informed commercialization strategy. Her role includes tracking hydrogen hub funding and stakeholders along with facilitating introductions and meetings with other potential partnerships.

Business Valuation and Acquisition Strategy

Tanya provides independent asset valuations and acquisition strategy for investors in the energy industries.

- She serves as an independent expert to estimate the appropriate cost of capital for assets under dispute as part of regulatory, litigation and valuation projects.
- For energy storage companies, advises on market entry strategy, market benefits including price and carbon emissions reductions, portfolio of value propositions, and potential value of proposed projects.
- For developers and asset owners of generation and transmission projects, performs benefits study of the plant's impact on environmental emissions and energy prices in the region.
- Serves as an independent appraiser for valuation, transaction support, and disputes, including appraisals of traditional power generation assets, cogeneration facilities, natural gas assets, and renewable power portfolios.
- For new entrants and emerging players, values enterprises, power assets, power purchase agreements, tolling arrangements, and trade books.
- Provides utilities and independent power producers with due diligence and advice relating to power purchase agreements, contract renegotiations, merchant plant investment opportunities and valuation of non-utility generation assets.

Renewable Resources

Tanya's work for renewables includes advice to developers and expert testimony on benefits and costs of new renewable projects, as well as renewable portfolio assessments.

- Assesses value of wind farms and renewable generation assets as merchant and contracted facilities, and incorporates the impact of such assets into market dynamics.
- Applies understanding of environmental attribute markets and regulations, including production tax credit, investment tax credit, net metering credits, RPS requirements. design and implementation of generation information system tracking systems and markets for renewable energy credits.

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- Served as key litigation strategist for a client defending against a nearly $1 billion damages claim related to alleged breach of wind turbine supply agreements. Responsible for managing the entire project, including two testifying experts, overseeing research on markets turbine and nacelle prices, availability, market conditions, discovery and damages.
- Advised the Ontario Ministry of Science and Technology on policy to promote green power and renewable resource development.
- For a commercial company located in Massachusetts, analyzed the costs, benefits and risks of pursuing installation of solar energy arrays under the state and federal regulatory regime, assisting the owner with soliciting potential developers.

Energy Storage

Tanya has developed strategic plans, originated business opportunities, and assessed the value of microgrids and energy storage opportunities.

- Performs market valuation of energy storage assets using market prices under different volatility assumptions and using production cost model projections, including short-term and long-duration storage technologies.
- Projects project benefits to that broader system, including reduction in electricity prices, carbon emissions and recapture of overgeneration.
- Provides updates on regulatory rules relating to energy storage facilities.
- Applies deep understanding of alternative energy storage technologies, including pumped storage, long-duration storage, batteries, flywheels and hydrogen-based storage technologies and their role in electricity markets.
- Designs high-level strategic framework and cost-effective microgrid design for municipality looking to improve its reliability and resiliency which achieving its carbon emission reduction goals.
- Assesses the potential benefits of contracted energy storage to system prices, carbon emissions and winter resiliency.

Transmission

Tanya has been involved extensively in long-distance transmission lines and independent transmission businesses, providing new entrant strategy and transaction support for investments in US commercial transmission, advising transmission developers on potential markets, customer acquisition, regulatory strategy and financing options.

- For a generation association, analyzed the sources and uses of a proposed high voltage direct current transmission line into New York City, including the potential impacts on power flows.
- For a consortium of generators, analyzed the costs and benefits associated with building a new high voltage direct current transmission line from Canada into the Northeast.
- For a multi-billion dollar international transmission company, provided strategic advice on market structure, regulatory organization and strategy, investment opportunities, and asset acquisition opportunities.

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- For a large rail company, advised on potential use of existing rights of way for development of transmission lines, including advice on specific transmission opportunities, identification of strategic regions and potential partners.
- For a multi-billion utility, advised on their commercial transmission strategy and development opportunities.
- For a multi-billion dollar oil and gas pipeline company interested in expanding their energy transportation portfolio into electric transmission, provided new entry strategy and successfully presented to the Board, launching the firm's initiative to develop a commercial transmission business in North America.
- For a large utility interested in pursuing a commercial transmission business, provided strategic advice on regions, strategic partners and target projects, including bidding strategy on acquisition of an operational transmission line.
- For the triennial rate review of a transmission upgrade in California, submitted expert testimony on the benefits of the transmission upgrade.
- For a transmission line under development in the southwest, assessed the size and potential markets for transmission service.
- For large utilities interested in developing a commercial transmission business, advised on entry strategy, potential acquisitions, and performed due diligence on specific acquisition targets.
- On behalf of an independent transmission company, assessed transmission asset acquisitions valued at over a billion dollars.
- Advised generation owner on regulatory strategy to create independent transmission company for purposes of developing high voltage interconnection (1,000 MW of capacity).

Competitive Procurement

Tanya has helped billion-dollar companies to design and implement competitive procurement processes for energy and energy assets.

- Designs and manages competitive procurement processes, including review of power procurement agreement, credit requirements, request for proposal process, and auction.
- Designs and manages transmission open season and bilateral negotiations for transmission capacity.
- Assesses long-term and short-term gas contracts in the context of hedging plays against other energy contracts, including tolling agreements and long-term power purchase agreements.

Corporate Restructuring

Tanya advises all aspects of the capital structure on valuation of power generation and delivery assets and securitization options in high-profile restructurings in the electricity industry.

- For the Oversight Committee of Puerto Rico, assessed the date of insolvency for the Puerto Rico electric utility (PREPA), the Commonwealth and a number of other government entities.

- For the ad hoc equity committee of a large renewable developer, provided valuation insight into the remaining assets and advice on potential strategies to pursue to obtain standing as an official equity committee.
- For investors in a large Texas utility with a significant competitive generation portfolio, provided pre-bankruptcy filing advice regarding generation asset valuation and impacts of proposed market changes pertaining to Interim Solution B+.
- For the unsecured creditors committee of a bankrupt portfolio of coal plants located in New York, provided industry expertise, valuation, market assessments, and settlement advice.
- For the unsecured creditors committee of a bankrupt coal plant located in New England, provided industry expertise, valuation, power contract assessment, damages calculations, market assessments, and settlement advice.
- For the bondholders of a waste coal facility undergoing restructuring in Pennsylvania, provided project valuation, assessed project cash flows and debt capacity, interfaced with the company's financial advisor, and advised on changing market conditions.
- For the Enron estate, analyzed insolvency analyses under the three legal tests: balance sheet, cash flow and capital adequacy. Analyses included assessing the tradebook for purposes of identifying debt-like transactions and performing cash flow projections of debt repayment and capital requirements. Analyzed tradebook entries, energy contracts, and hundreds of legal documents to rebook more than $3.5 billion of off-balance sheet transactions for purposes of understanding when the company was insolvent. Settlement with various parties totaled more than $6 billion.
- For a bankrupt tradebook, developed summary synopses on mark-to-market accounting and the marketable value of trade books and examines trader activities for market manipulation and non-compliance with regulatory requirements. Tanya also has analyzed tradebook entries, energy contracts, and hundreds of legal documents to rebook off-balance sheet transactions into the financial statements of a bankrupt energy market's estate.
- For a large, publicly-traded energy marketer, Tanya reviewed tradebook for wash trades and market manipulation, revalued tradebook and assessed controls on trading operations before and after conveyance.

Market Assessments and Electricity Market Design

- Tanya understands the economic underpinnings of competition, economic incentives and market rules for both competitive wholesale and retail markets. Tanya regularly performs market assessments of wholesale energy and capacity markets for market participants, including assessment of the impact of alternative market rules and regulations and strategic advice for regulatory positioning.
- Develops and directs analyses of market conditions using locational marginal pricing market models, zonal prices and industry data.
- Advises on policy recommendations concerning market design and implementation, and authors white papers and expert testimony regarding research and findings.
- Economic expert to market participant trade associations across multiple northeast electricity markets on market rule changes submitted to FERC, including for ISO-NE and PJM.

- Served as a key advisor to the Singapore Public Utilities Board (subsequently Energy Markets Authority) on developing a competitive wholesale and retail electricity market, including market rules, licenses and codes (2000-2004) and primary advisor and project manager to the Ontario Market Design Committee, Ontario Energy Board, Ministry of Energy, Science and Technology and market participants on competitive market design, regulatory structure, environmental policy and risk management (1998 - 2001).

PUBLICATIONS

- "Greenwashing, Greenhushing, And Greenbashing: Risks And Perils", Client Alert, October 2023
- "How Evolving ESG Disclosure Regulations Impact You", Client Alert, October 2023
- "Greenhouse Gas Reductions: Finding Your Way Forward", Client Alert, October 2023
- "Carbon Inventories: California Here We Come!", Client Alert, October 2023
- "ESG Is A Four Act Play And Intermission Is About To End:, Client Alert, October 2023
- "Why Energy Trading Cos. Must Review Electronic Comms Policy", Law360, September 2023
- "The Widening New Zero: Why Your Company May Have To Start Accounting For Carbon" Client Alert, August 2023
- "How Data Centers Facilitate The Clean Energy Transition And Help Grid Reliability", Power Grid International, July 2023
- "Full Disclosure: It Is Time To Come Clean On Crypto's Wash Trades", Client Alert, March 2023
- "Full Disclosure: Banking ESG – Ode To Good Governance", Client Alert, March 2023

Column in Electric Light & Power and Executive Digest, Pennwell Publications

- "The Almighty Load: How Electricity is Finding a New Religion," November/December 2019
- "Beware the Green Badge of Courage," September/October 2019
- "The Role of Retail in Renewables" July/August 2019
- "The Story on Storage: Is it Truly Charging Ahead?" May/June 2019
- "Hey Google! How Much does my Energy Cost?" March/April 2019
- "Realizing Carbon Reduction Goals: Assessing the Merits of Carbon Tax," January/February 2019
- "The Evolution of Resiliency: Will the Frog Turn into a Prince?" November/December 2018
- "Imagine a Market that . . ." September/October 2018
- "Is the Great Experiment of Wholesale Electricity Competition Ending?" May/June 2018
- "Leveling the Playing Field for Storage: Can Markets Figure It Out?" March/April 2018
- "Big Data, Bit Coin and Blockchain: How will Energy Cash In?" January/February 2018
- "Resistance to Resilience: ISO/RTO Response to DOE's NOPR," November/December 2017
- "Is your SCADA System Safe?" September/October 2017
- "So What's in Your Grid Modernization Plan?" July/August 2017
- "Nuclear Friction: Challenging the Economic Rationale of State Support," May/June 2017
- "Valuing Lost Load: How the Economics have Changed," March/April 2017
- "Digitizing Electrons: How are You Incorporating the Digital Economy into Utility Operations?" January/February 2017

- "What You Can Do to Decrease Operational Risk Part II: Securing your Supply Chain," November/December 2016
- "How Operational Risk is Increasing and What you Can Do About It: Part I," September/October 2016
- "Living on the Edge: Seeing Things in a Different Way to Transform the Grid," July/August 2016
- "Listening to the Supremes: Impacts of Judicial Decisions on Power Markets," May/June 2016
- "When will Oil Prices Recover? Three Economic Theories Provide Different Answers," January/February 2016
- "The Internet of Things: Where the Power Sector Connects," November/December 2015
- "A Synopsis of Changes in the Finalized Clean Power Plan," September/October 2015
- "Priming the Power Sector: Will Performance Pay?" July/August 2015
- "Pay Attention to the Man behind the Meter," March/April 2015
- "2015 in Preview: Harbingers Ring in the New Year," January/February 2015
- "What do Lower Oil Prices Mean for the Power Sector?" November/December 2014
- "For Sail: Mega Merger Tactics in the Electricity Industry," September/October 2014
- "Who's on First? Ongoing Challenges to FERC's Jurisdiction," July/August 2014
- "How Big Data is Becoming a Bigger Deal for the Power Sector," May/June 2014
- "Transformative Technologies to Watch During the Next 2 Years," March/April 2014
- "Why Google Bought Nest for $2.3 Billion," January/February 2014

Column in Natural Gas & Electricity, Wiley Periodicals, Inc., a Wiley Publication

- "Shale's Big Impact on US Manufacturing: Boom or Bust?" November 2014
- "Why Virtual Pipelines Transporting CNG are becoming a Reality," August 2014
- "Parallel Play: Coordinating Natural Gas and Electricity Markets," May 2014
- "Understanding the Recent Volley in Natural Gas Prices," March 2014
- "Outlook – Spark Spreads, Dark Spreads, and Bed Spreads Showing Cutthroat Competition," January 2014
- "NGLs versus LNG: The Fight of the Century," November 2013
- "Natural Gas Could Bring Overseas Jobs Back to the United States," October 2013
- "Pop Go Gas Prices: Has the Market Recovered?" July 2013
- "Waste Makes Haste: Low-Cost Power Plants Scramble to Keep Pace," May 2013
- "Price Impacts of Regulating the Worldwide Fracking Frenzy," March 2013
- "Natural Gas Challenges King Coal: Check or Checkmate?" January 2013
- "A Midsummer Night's Dream: Why Natural Gas Prices Still Sleep," November 2012
- "The Yin and Yang of Natural Gas Prices and Renewable Resources," September 2012
- "Electricity and Natural Gas Dance: It Takes More than Two to Contango," May 2012

Speaking and Presentations

Tanya is an established speaker and moderator at industry conferences, offering market insights and identification of strategic opportunities for attendees, a selection of which is below:

- "Energy Outlook," MT Forecast Conference, "Energy Trends and Transition: How the Energy Transition is Transitioning," October 10, 2024
- "Energy Outlook," MT Forecast Conference, "Energy Outlook," October 2022
- "Energy Outlook," MFG2021+MT Forecast Conference, November 4, 2021
- "The Increasingly Uncooperative Oil Industry," MT Forecast Conference, October 27, 2020
- "Projecting the Pace of a Renewable Resource Revolution," MT Forecast Conference in pre-recorded session, October 27, 2020
- "Tapping into the Power of Offshore Wind," Presentation to the Connecticut Power and Energy Society and New England Women in Energy and Environment, September 11, 2019
- "The Ever-Tightening Convergence of Power, Oil, and Gas," MT Forecast Conference, October 11, 2018
- "Ever-Expanding Opportunities in Alternative Energy," MT Forecast Conference, October 11, 2018
- "Evolving New England Energy Markets and what it Means for Consumers," New England Consumer Liaison Group, March 3, 2018
- "Natural Gas Storage in New England and the Impact of LNG on Winter Prices," New England Association of Energy Engineers, January 5, 2016
- "New England Pipeline and Transmission Infrastructure: Recent Studies," New England Electricity Restructuring Roundtable, November 20, 2015
- "Two Perspectives on the Clean Power Plan: New England vs. Texas," Infocast 2nd EPA Clean Power Plan Implementation Summit Multi-State Perspectives, Plans and Implications of 111(d), October 20, 2015
- "Future of Energy Development: Energy Trends and Opportunities," Global Forecasting and Marketing Conference, Association for Manufacturing Technology, October 14, 2015
- "Energy Trends and Opportunities," United States Cutting Tool Institute, Spring Meeting, May 3, 2015
- "Status of Proposed Rules," EPA Clean Power Plan Implementation: Multi-state Perspectives, Plans and Implications of 111(d), April 1, 2015
- "Energy Trends and Opportunities for the Heat Exchange Industry," Heat Exchange Institute, March 22, 2015
- "Economic Impacts of Environmental Regulations on ERCOT: Bringing it down to dollars and sense," Infocast EPA Clean Power Plan Implementation (Conference Chair and Speaker), February 25, 2015
- "Capital Expenditures in the Energy Industry," American Manufacturing Technologies Global Marketing and Forecasting Conference, October 15, 2014
- "The Future of Energy in New England," Northeast Energy Commerce Association Annual, May 14, 2014
- "Impacts on Texas Plant Valuations and Potential M&A," Infocast ERCOT Market Summit (moderator) and Pre-Summit Forum (chair and speaker), February 25, 2014
- "Energy Trends: Why Jobs, Capital Investment and Trade are Heating Up," Association for Manufacturing Technology 2013 Global Forecasting and Marketing Conference, October 16, 2013
- "Energy Trends: Pricing Trends in the Midwest," Infocast Black Gold Conference, September 20, 2013
- "Energy Markets: Pricing Trends in the Midwest," Infocast Reshoring Summit: Brining Manufacturing back to the U.S., March 12-13, 2013

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- "Gas-fired Power Generation as a Driver for New Demand and Pipelines," Marcellus and Utica Infrastructure Summit, Infocast Conference, Pittsburgh, PA, July 12-13, 2012
- "Competitors or Collaborators? Exploring the Interplay between Renewable Energy & Other Fuel Sources," Wall Street Renewable Energy Finance Forum, New York, June 19-20, 2012
- "Executive Briefing: Power Market Trends Impacting the Value of Power Assets," Executive Session Moderator, Power Generation Asset Financing Summit, New York, May 19-21, 2012
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- "A Brief Review of New Institutions and Structures in the Electricity Industry," Presented to the GEMI Power Conference, Houston, Texas, June 29, 2006

PROFESSIONAL AFFILIATIONS / OTHER

- Northeast Energy Commerce Association, President Emeritus
- New England Women in Energy and the Environment
- International Chamber of Commerce, Vice Chair, Center for Expertise
- Energy Bar Association, Non-legal Member
- Town of Cohasset
  Alternative Energy Committee, Chair (2010 – 2013; 2019 – present)
  Advisory Committee (2013 - 2019)

PRIOR POSITIONS

- Energyzt, Executive Director
- FTI Consulting, Managing Director
- Charles River Associates, Inc. (CRA International), Vice President/Principal
- Putnam, Hayes & Bartlett, Principal/Senior Associate/Associate

EXHIBIT B
DOCUMENTS RELIED UPON

Case Filings, Depositions, Expert Reports

- IN THE UNITED STATES BANKRUPTCY COURT FOR THE SOUTHERN DISTRICT OF TEXAS HOUSTON DIVISION In re: ZACHRY HOLDINGS, INC., *et al.*,1 Debtors., Chapter 11, Case No. 24-90377 (MI) (Jointly Administered):
  - ORDER GRANTING COMPLEX CHAPTER 11 BANKRUPTCY CASES TREATMENT, Case 24-90377 Document 23 Filed in TXSB on 05/21/24.
  - OMAHA PUBLIC POWER DISTRICT'S APPLICATION FOR ALLOWANCE OF ADMINISTRATIVE EXPENSE CLAIM, Case 24-90377 Document 2176 Filed in TXSB on 02/14/25.
  - ORDER GRANTING OMAHA PUBLIC POWER DISTRICT'S APPLICATION FOR ALLOWANCE OF ADMINISTRATIVE EXPENSE CLAIM, Case 24-90377 Document 2176-1 Filed in TXSB on 02/14/25.
  - DECLARATION OF MOHSIN Y. MEGHJI IN SUPPORT OF THE DEBTORS' SETTLEMENT AND ASSUMPTION MOTION, Case 24-90377 Document 810 Filed in TXSB on 08/26/24.
- ENGINEER, PROCURE, AND CONSTRUCT CONTRACT FOR OMAHA PUBLIC POWER DISTRICT STANDING BEAR LAKE AND TURTLE CREEK GENERATING STATIONS, CONTRACT NO. 263406, September 21, 2021, Omaha Public Power District, Zachry Industrial Inc., and the following Exhibits:
  - EXHIBIT D, PROCUREMENT AGREEMENT, 2021, Omaha Public Power District, Siemens Energy, Inc., CTR 236406.
  - EXHIBIT D, CONTRACT 261740, PROCUREMENT AGREEMENT FOR RECIPROCATING INTERNAL COMBUSTION ENGINES FOR OPPD'S STANDING BEAR LAKE STATION, June 30, 2021, Omaha Public Power District, Wärtsilä North America, Inc., CTR 236406.
  - EXHIBIT E, GUARANTEED COMPLETION DATES AND PROJECT SCHEDULES, CTR 236406.
  - EXHIBIT F, PERFORMANCE GUARANTEES, CTR 236406.
  - EXHIBIT G, MILESTONE PAYMENT SCHEDULES, CTR 236406.
- AMENDMENT NO. 1 to Contract No. 263406, November 9, 2023, Omaha Public Power District, Zachry Industrial Inc.
- AMENDMENT NO. 2 TO ENGINEER, PROCURE, AND CONSTRUCT CONTRACT FOR OMAHA PUBLIC POWER DISTRICT STANDING BEAR LAKE AND TURTLE

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IN THE UNITED STATES BANKRUPTCY COURT
FOR THE SOUTHERN DISTRICT OF TEXAS HOUSTON DIVISION
Chapter 11, Case No. 24-90377 (MI), Adversary No. 25-03025 (MI)
Declaration of Tanya Bodell

EXHIBIT C: Acronyms

EXHIBIT C
ACRONYMS

Acronym	Definition
AEO	Annual Energy Outlook, refers to an annual report published by the U.S. Energy Information Administration (EIA) in accordance with the Department of Energy Organization Act of 1977, which requires the EIA to prepare an annual report that contains trends and projections of the energy consumption and supply
AS	Ancillary Services, refers to the services necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission system. The Integrated Marketplace will set prices for certain ancillary services such as Operating Reserves, as part of both the Day-Ahead Market and the Real-Time Balancing Market
Btu	British Thermal Units, a common metric for natural gas volume traded on the wholesale market
CONE	Cost of New Entry, calculated by SPP as part of the basis for assessing penalties on market participants that fail to meet their RAR. CONE is based on the estimated annual capital and fixed operating costs of a hypothetical natural gas-fired peaking facility, and the CONE value is set forth in the Tariff. Id. § 13.0 (Cost of New Entry) (0.0.0). The CONE reflects the long-run marginal cost of new entry and is an economic concept used in multiple capacity markets including ISO-NE, MISO, NYISO, and PJM
CT	Combustion Turbine, the generation technology that OPPD procured from Siemens for the Turtle Creek Station
DP	Distribution Provider per NERC definition, meaning "Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider . . ."
EIA	Energy Information Administration, the statistical and analytical agency within the U.S. Department of Energy, which collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment
EPC	Engineer, Procure, and Construct, referenced with respect to the Original EPC Contract, First Amended EPC Contract, and Second Amended EPC Contract between OPPD and Zachry

Acronym	Definition
ERCOT	Electricity Reliability Council of Texas, which operates the transmission system and wholesale electricity markets to the South of SPP in a subset of Texas
FERC	Federal Energy Regulatory Commission, the federal agency responsible for regulating oil and gas pipelines and markets, interstate and independent transmission, and wholesale electricity markets
GO	Generation Owner per NERC definition, meaning "The entity that: 1) owns and maintains generating Facility(ies) (Category 1 GO); or 2) owns and maintains non-BES inverter based generating resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV (Category 2 GOP)."
GOP	Generation Operator per NERC definition, meaning "The entity that: 1) operates generating Facility(ies) and performs the functions of supplying energy and Interconnected Operations Services (Category 1 GOP); or 2) operates non-BES inverter based generating resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV (Category 2 GOP)."
GW	Gigawatt, measure of electric power equal to 1,000 MW used to describe the capacity of wholesale electrical systems
ICE	Intercontinental Exchange, Inc, operates a global financial exchanges and clearing houses and provides data and listing services on futures settlements for energy and environmental products in the U.S.
ISO	Independent System Operator, responsible for operating the high-voltage electrical transmission system and wholesale electricity markets
ISO-NE	Independent System Operator of New England, which operates the transmission system and wholesale electricity markets in New England, including Connecticut, Massachusetts, New Hampshire, Rhode Island, Vermont, and most of Maine
kW	Kilowatt, a measure of instantaneous energy that is 1 thousand watts and typically used to measure power capacities on small scale
kWh	Kilowatt-hour, a measure of energy produced by 1 KW for an hour
kW-month	Kilowatt-month, a measure of capacity in kilowatts available on a monthly basis

Acronym	Definition
LMP	Locational Marginal Price, the market-clearing price for energy at a given price node equivalent to the marginal cost of serving demand at the price node while meeting SPP Operating Reserve requirements
LRE	Load Responsible Entity, including regulated utilities, self-regulated municipalities and public power districts, and competitive retailers who are responsible for serving customer demand for electricity
MISO	Mid-Continent Independent System Operator, which operates the transmission system and wholesale electricity markets in a subset of midwestern states to the east of SPP
mmBtu	Million British Thermal Units, a common metric for natural gas volume traded on the wholesale market
MUD	Metropolitan Utilities District, which is a public utility location the greater Omaha area that provides natural gas and water services to the community
MW	Megawatt, a measure of instantaneous energy that is 1 million watts and 1,000 kilowatts, typically used to measure power capacities on large scale
MWh	Megawatt-hour, a measure of energy produced by 1 MW for an hour
NERC	North American Electric Reliability Corporation
Net CONE	CONE less net revenues from energy and ancillary services projected to be received by a new entrant that builds a power generation plant in the region
NGI	Natural Gas Intelligence, a provider of natural gas price transparency and key news, insights, and data for the North American energy markets
NNG	Northern Natural Gas Pipeline, a natural gas pipeline system that stretches across 11 stations, from Southern Texas to Michigan's Upper Peninsula, providing access to five of the major natural gas supply regions in North America
NYISO	New York Independent System Operator, which operates the transmission system and wholesale electricity markets in New York
OATT	Open Access Transmission Tariff, a set of rules and regulations that ensure all customers have non-discriminatory access to a utility's transmission system
OPPD	Omaha Public Power District, a public electric utility in the state of Nebraska
PJM	PJM Interconnection, LLC, which operates the transmission system and wholesale electricity markets for all or part of 13 states (including, but not limited to Pennsylvania, New Jersey and Maryland) and the District of Columbia

Acronym	Definition
PPA	Power Purchase Agreement
PRA	Planning Resource Auction, an annual auction performed by MISO to ensure sufficient Planning Resources in each Local Resource Zone and to calculate Auction Clearing Prices for each Local Resource Zone while respecting sub-regional constraints and transmission limitations
PRM	Planned Reserve Margin, represents the amount of power utilities must have available beyond peak projected demand to guard against unplanned situations or stresses on the regional power grid
RAR	Resource Adequacy Requirement, established by SPP as an obligation imposed on the registered LREs to maintain sufficient resources given their load requirements
RICE	Reciprocating Internal Combustion Engines, the generation technology that OPPD procured from Wartsila for the Standing Bear Lake Station
RP	Resource Planner per NERC definition, meaning "The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority area
SPP	Southwest Power Pool, which operates the transmission system and wholesale electricity markets for all of Kansas and Oklahoma, as well as portions of North Texas, Nebraska, Arkansas, Iowa, Louisiana, Minnesota, Missouri, Montana, New Mexico, North Dakota, South Dakota, and Wyoming
TO	Transmission Owner per NERC definition, meaning "The entity that owns and maintains transmission Facilities."
TOP	Transmission Operator per NERC definition, meaning "The entity responsible for the reliability of its local transmission system and operates or directs the operations of the transmission Facilities."
TP	Transmission Planner per NERC definition, meaning "The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area."
V O&M	Variable Operations and Maintenance

EXHIBIT D: Methodology

EXHIBIT D
METHODOLOGY

This Exhibit describes the methodology used to estimate economic damages on both an ex-post and ex-ante basis.

As a general rule, economic damages is equal to what actually happened ("Actual World") less what would have happened if the harm had not occurred ("But-for World").[79] I am informed by Counsel that Nebraska law is consistent with this approach with respect to Breach of Contract:

> "the measure of damages for a breach of a contract claim is an amount that would place [the plaintiff] in as good a position as it would have enjoyed if the contract had been performed."[80]

Therefore, a proper calculation of economic damages should consider the costs that OPPD incurred in the Actual World that would have been different in the But-for World.

D.1 EX-POST ESTIMATE OF ECONOMIC DAMAGES

An ex-post estimate of economic damages uses whatever information is available up to the report date, or a date slightly prior to the report date to allow for incorporation into the analysis. An ex-post calculation of damages can be updated as of the judgment date, or a date specified by the Courts, using the same methodology and source of assumptions updated for new information

[79] Among other references in Exhibit B, see for example:

Mark A. Allen, Robert E. Hall, and Vicotria A. Lazear, National Academies of Sciences, Engineering, and Medicine. 2011. Reference Manual on Scientific Evidence: Third Edition. Washington, DC: The National Academies Press. https://doi.org/10.17226/13163. "Reference Guide on Estimation of Economic Damages." National Academies of Sciences, Engineering, and Medicine. 2011. Reference Manual on Scientific Evidence: Third Edition. Washington, DC: The National Academies Press. https://doi.org/10.17226/13163.

[80] *Infogroup, Inc. v. Database LLC*, 956 F.3d 1063, 1068 (8th Cir. 2020) (approving jury instruction so stating; citing *Bachman v. Easy Parking of America, Inc.*, 562 N.W.2d 369, 373 (Neb. 1997)).

that has become available as of the specified date. For purposes of this Declaration and calculation of damages, the ex-post date is April 15, 2025 and information available as of the date of this Declaration to inform economic damages up to April 15 is used.

The methodology for calculating economic damages is to estimate the incremental cost to OPPD due to the delay in Substantial Completion. In the absence of the Facilities, OPPD would either have: 1) Reduced sales; or 2) Higher purchase costs to procure the delayed Electricity Product. The cost is therefore equal to the quantity that the Facilities would have produced times the market price less production costs, regardless of how OPPD procured the replacement power required due to the delay. Therefore Economic Damages are as follows:

Economic Damages = Actual World less But-for World

= Higher Purchase Costs less Costs to Produce (Generate)

= Market Value less Cost to Produce

In the case of the Facilities, the Cost to Produce is the cost of producing the electricity product (e.g., energy, ancillary services, and capacity). The Market Value generally would be considered the market price times the quantity that the Facilities would have produced.

D.1.1 Economic Damages of Delayed Energy

OPPD anticipated that the Facilities would operate as peaking units and produce energy around 15 percent of the time during peak hours. Whether or not the Facilities produce energy depends on whether it is more or less economic for OPPD to procure energy from SPP's energy markets. If the SPP price for energy is higher than the variable cost of production (i.e., fuel and variable operations & maintenance costs) of the Facilities to produce energy, it would be economic for OPPD to sell energy into the SPP wholesale electricity markets. If the SPP market clearing

price is below the variable cost of the Facilities to produce, SPP would not dispatch the Facilities to produce energy. Therefore:

Energy Damages = Actual World less But-for World

= Market Price for Energy x Quantity less Cost to Generate Energy

Where:

- Market Price for Energy = Quantity of Energy x Price
- Cost to Generate = Quantity of Energy x (Natural Gas Price x Heat Rate + VOM)
- Quantity of Energy = Amount of energy the Facilities would have produced estimated based on an economic dispatch of the Facilities estimated by comparing the market price for energy to the variable cost of production (i.e., Natural Gas Price x Heat Rate + VOM)
- VOM = Variable O&M

D.1.2 Economic Damages of Delayed Ancillary Services

In general, ancillary services are required to maintain reliability of a transmission system. SPP procures ancillary services through the operating reserve market. SPP uses the operating reserve markets to ensure the amount of generation matches load on a subinterval basis. Generators automatically respond to regulation instructions in seconds while spinning and supplemental products are reserved for contingency situations and can respond to instructions within ten minutes. The Facilities were anticipated to help meet reserve requirements and supply power during peak periods.[81] The technology at both of the Facilities has fast-start and fast-ramp capabilities.[82] To the extent the Facilities can provide other ancillary services that could be

[81] OPPD, https://www.oppdcommunityconnect.com/power-with-purpose

[82] For example, the Wartsila RICE units are fast-starting capable in order to provide rapid response to fluctuations in supply and demand.

qualified and sold to SPP, economic damages associated with each type of ancillary services would be quantified as follows.

Ancillary Services Damages = Actual World less But-for World

= Market Price for AS x Quantity less Cost to Produce AS

Where:

- AS = Ancillary Services
- Market Price for Ancillary Services = SPP Market Price for each type of ancillary services x the Quantity of each type of ancillary services that the Facilities would have produced
- Prices = As reported by SPP for Regulation-Down and Spinning Reserves
- Quantity of each type of ancillary services that the Facilities would have produced can be estimated based on:
  - *OPPD Plant Capacity:* Applies the reported capacity of the two Facilities to either Regulation-Down or Spinning Reserves, based on whether they are operating or not operating.
  - *OPPD's Expectations:* OPPD's stated expectation regarding which of the Facilities would have produced ancillary services and which type.
  - *Technical Specifications vs. SPP Requirements:* Analysis of the technology specifications of each of the Facilities and whether they would qualify to provide ancillary services in the SPP markets.
  - *Market Size for Qualified Ancillary Services:* Reported actual historical amount of ancillary services of the type(s) for which the Facilities would have qualified.
  - *Market Share:* Estimated amount of market share that the Facilities would have been able to capture given other resources available in SPP to supply ancillary services.

Wartsila, https://www.wartsila.com/docs/default-source/energy-docs/technology-products/product-leaflets/wartsila-50df.pdf?sfvrsn=e9eda345_20

- Cost to Produce Ancillary Services = Conservatively assumed to be Zero if the Facilities had been operational as the capacity available to supply ancillary services would be in place with essentially the same fixed costs under the milestone payments that are similar in both the Actual and But-for Worlds.[83] Spinning reserves would incur some fuel and variable O&M, but is ignored for now.

D.1.3 Economic Damages of Delayed Capacity Value

The Facilities provide capacity and help OPPD to meet its SPP-mandated reserve requirements.

Capacity Damages = Actual World less But-for World

= Cost to Procure Capacity less Cost to Produce Capacity

Where:

- Cost to Procure Capacity = MISO capacity market price for Iowa to serve as a proxy for bilateral market prices for capacity that OPPD could buy from third parties.

- Cost to Produce Capacity = Zero, assuming the fixed costs for the Facilities are the same in both the Actual World and the But-for World.

The price for capacity for MISO's Iowa zone is used as a proxy for the bilateral price for capacity that OPPD may have entered into, which would be indicated by disclosure of transactions for capacity associated with replacing the delayed capacity from the Facilities.

D.2 EX-ANTE ESTIMATE OF ECONOMIC DAMAGES

An ex-ante estimate of economic damages establishes a "date certain" after which no new information can be used. The concept of an ex-ante approach to estimating damages is that the

[83] Although OPPD benefits from a delay in the final payments once Substantial Completion is achieved, we ignore this benefit to OPPD as a conservative assumption for now to illustrate the disparity between the Liquidated Damages and economic damages calculation.

wrongdoing tied to liability for which economic damages is being calculated sets the date of damages and any information available after that point is not relevant as the damaged party effectively has incurred the harm at that point in time. Ex-ante calculations are used to estimate damages as of an historical point in time when the wrongdoing that leads to liability is a one-time event and the harm to the damaged party is foreseeable.

In this case, economic damages are an ongoing event that can extend over multiple months due to ongoing delays past the Guaranteed Substantial Completion Date. That said, a reasonable expectation of economic damages can be calculated using estimated quantities that the Facilities could have produced, futures price data, and known pricing for market-based products that are sold on a forward basis (e.g., ancillary services and capacity).

For purposes of this Declaration, the ex-ante date is used to illustrate the ease with which a reasonable projection of economic damages could have been performed and incorporated into the Second Amended EPC Contract. Per direction of Counsel, I use August 1, 2024, the date of the Second Amended EPC Contract, to illustrate how economic damages can be forecasted on a going-forward basis using market instruments that would have allowed OPPD to hedge their exposure to a delay in the Guaranteed Substantial Completion Date using futures and forwards.

EXHIBIT E: Assumptions

EXHIBIT E

ASSUMPTIONS

E.1 EX-POST HISTORICAL ANALYSIS

Key inputs used to calculate damages using the ex-post approach and actual prices that occurred include the following:

- Damages Period
- Plant Heat Rate
- Variable O&M
- Quantity
- Energy Price
- Ancillary Services Price
- Capacity Price

This section provides additional detail on each of these assumptions.

E.1.1 Damages Period

The calculation of economic damages is for the period beginning the day after the Guaranteed Substantial Completion Date listed in the Second Amended EPC.[84] For the Turtle Creek Station, this includes December 17, 2024 to April 15, 2025. For the Standing Bear Lake Station, this includes December 31, 2024 to April 15, 2025. The selected period encompasses the liquidated damages start date for both plants and extends to a reasonable date close to the submission of this report, when actual pricing data could still be acquired. While far past the

[84] Second Amended EPC, Section 7 and Section 8.

acceleration date to cap per Amendment No. 2, the value of April 15 serves to illustrate the extreme discrepancy between Liquidated Damages versus the economic damages OPPD incurred.

E.1.2 Variable Operations & Maintenance

These costs of running a power plant includes variable operations and maintenance ("Variable O&M") costs tied to running the equipment and can include things like consumable materials, such as lubricants and chemicals, as well repairs and maintenance. The type of plant and technology being used will also impact the amount of variable O&M incurred. While often minimal, it is an important cost component to consider when modeling a plants operation.

For purposes of the damages estimate, I apply the variable O&M expenses below to each hour when the plants are operating.

- **Turtle Creek Station:** $4.50/MWh
- **Standing Bear Lake Station:** $5.50/MWh

These assumptions are aligned with the typical variable O&M costs of similar plants in the market today.

E.1.3 Heat Rate

Heat rate is a key performance indicator and represents the efficiency of a power plant's ability to convert fuel into electricity. A plant with a higher heat rate requires more fuel to generate a unit of electricity, and thus making it less efficient. For a natural gas peaking plant, like the Facilities, the heat rate is generally higher than plants that operate more frequently, such as a natural gas combined cycle plant. This can be seen in **Figure E-1** below, which includes the average range of heat rates by plant type.

Figure E-1: Typical Heat Rates by Generation Type[85]

Unit Type	Typical Heat Rate (Btu/kWh)
Natural gas steam turbine	10,000 – 12,000
Natural gas combined cycle	6,200 – 8,000
Natural gas combustion turbine	8,000 – 10,000
Natural gas reciprocating engine	7.500 – 8,500
Coal steam turbine	9,000 – 11,000
Natural Gas Turbine with Cogeneration	5,000 – 6,500

The higher heat rate is a result of the quick start capability and infrequent operation, leading to a less efficient combustion process. The technology being used in the plant is also a key driver, as some technologies are more efficient than others, despite serving the same purpose, such as a peaking plant.

For purposes of my damage estimates, the heat rate had to be estimated since actual operational data is not available. In developing the assumption, the technology being used was a key consideration. The technologies installed at each plant are listed below:

- **Turtle Creek Station:** Combustion Turbines ("CT") consisting of two 225 MW Siemens Energy SGT6-5000F CTs (simple cycle turbines)[86]
- **Standing Bear Lake Station:** Reciprocating Internal Combustion Engines (RICE) consisting of nine 16.7 MW Wärtsilä 18V50DF RICE units[87]

Generally, a RICE unit, like the one being used in the Standing Bear Lake Station, are slightly

[85] This range reflects a generalized range for the technology type as reported by Enerdynamics, Energy Knowledgebase, https://energyknowledgebase.com/topics/heat-rate.asp

[86] OPPD, https://www.oppdcommunityconnect.com/standing-bear-lake-station

[87] OPPD, https://www.oppdcommunityconnect.com/turtle-creek-station

more efficient than a CT, like the one being used in the Turtle Creek Station. The heat rate assumption reflects this difference in technology as listed below:

- **Turtle Creek Station:** 9,000 Btu/kWh
- **Standing Bear Lake Station:** 8,000 Btu/kWh

For the Turtle Creek Station, a 9,000 heat rate reflects the mid-point of the average heat rate range and is also consistent with assumptions used by the U.S. Energy Information Administration in developing its 2025 Annual Energy Outlook (AEO).[88] For the Standing Bear Lake Station, an 8,000 heat rate reflects the mid-point of the average heat rate range and while the EIA is no longer modeling RICE units as part of its AEO, it aligns with prior assumptions used by the EIA in its past reports.[89]

The heat rate assumption used represents a conservative estimate of the heat rate the plants would likely see. Had the plants been operating at the 15% capacity factor projected by OPPD, it is likely they would have experienced slightly higher heat rates as a result of less frequent start-ups and shutdowns.[90] By applying a conservative estimate, the estimated damages represent the higher end of damages that would have likely occurred.

E.1.4 Quantity

Quantities that would have been produced under the contract are calculated on an hourly

[88] U.S. Energy Information Administration (EIA), Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies (January 2024), https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf

[89] EIA, Capital Cost and Performance Characteristics for Utility Scale Electric Power Generating Technologies (February 2020), https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_aeo2020.pdf

[90] OPPD, https://www.oppdcommunityconnect.com/turtle-creek-station; OPPD, https://www.oppdcommunityconnect.com/standing-bear-lake-station.

basis and dispatched based on simple economics (i.e., cost of production versus gross revenue). When it is economic for each of the Facilities to operate, the hourly quantity produced is based on the capacity in Megawatts (MW) for each of the Facilities, as reported by OPPD.[91] The assumed capacity values are as follows:

- **Turtle Creek Station:** 450 MW
- **Standing Bear Lake Station:** 150 MW

The OPPD website does not specify whether the reported values are the nameplate capacity of each plant or the qualified capacity size, which is often slightly less. I therefore reviewed the SPP Interconnection Facilities Study and found that the plant sizes submitted to SPP for interconnection to the SPP system include 510 MW for the Turtle Creek Station and 169.56 for the Standing Bear Lake Station.[92] The reported values in the study represent the nameplate capacity of the plant, and not necessarily where the plant would operate.

In order to confirm the reduced values on the OPPD website are reasonable, I performed a high-level calculation of the expected generating capacity of the plants versus the reported nameplate capacity. To do this, I reduced the nameplate capacity by industry rule of thumb rates for forced and planned outages (i.e., a 10 percent reduction for forced outages and a 2.5 percent reduction for planned outages) as follows:

[91] OPPD, https://www.oppdcommunityconnect.com/standing-bear-lake-station; OPPD, https://www.oppdcommunityconnect.com/turtle-creek-station

[92] SPP, Interconnection Facilities Study Report, GEN-2020-043, p. 1 of 52, September 2022, GEN-2020-043 Facility Study FINAL.pdf.

The SPP Interconnection Facilities Study represents a study conducted by SPP which evaluates the interconnection of the proposed facilities to determine the impact of the plants on the system, and particularly the transmission system. It represents a key step in the approval process before all proposed plants can be put into operation.

Adjusted Capacity = Nameplate Capacity X (1 – FO Rate – PO Rate)

Where: FO = Forced Outage PO = Planned Outage

The resulting value for each plant was 445.25 MW for the Turtle Creek Station and 148.37 MW for the Standing Bear Lake Station. Since these values were within a reasonable range of those reported on the OPPD website, it is reasonable to rely on the publicly reported OPPD adjusted capacity values.

As a second check for reasonableness, I also reviewed the EIA Form 860 Report, which collects generator specific information about existing and planned generators in the U.S.. The most recent Annual Report, released September 23, 2024,[93] and Electric Power Monthly Report, released April 24, 2025,[94] both list the Facilities under the planned generator section. The reports lists the Turtle Creek Station as having 528 MW Nameplate Capacity and 442.2 MW Winter and Summer Capacity. For the Standing Bear Lake Station, it is listed at 162.9 MW Nameplate Capacity and 151.2 MW Winter and Summer Capacity.[95] The close relationship between the values in the EIA 860 Report, the SPP Interconnection Report, and OPPD website give me confidence in the values used in my damage calculations.

E.1.5 Energy Price

Economic damages associated with energy are equal to the quantity times the hourly market price for electricity less the cost of production. Therefore, the price of electricity is the

[93] EIA, Form 860, https://www.eia.gov/electricity/data/eia860/

[94] EIA, Electric Power Monthly, https://www.eia.gov/electricity/monthly/

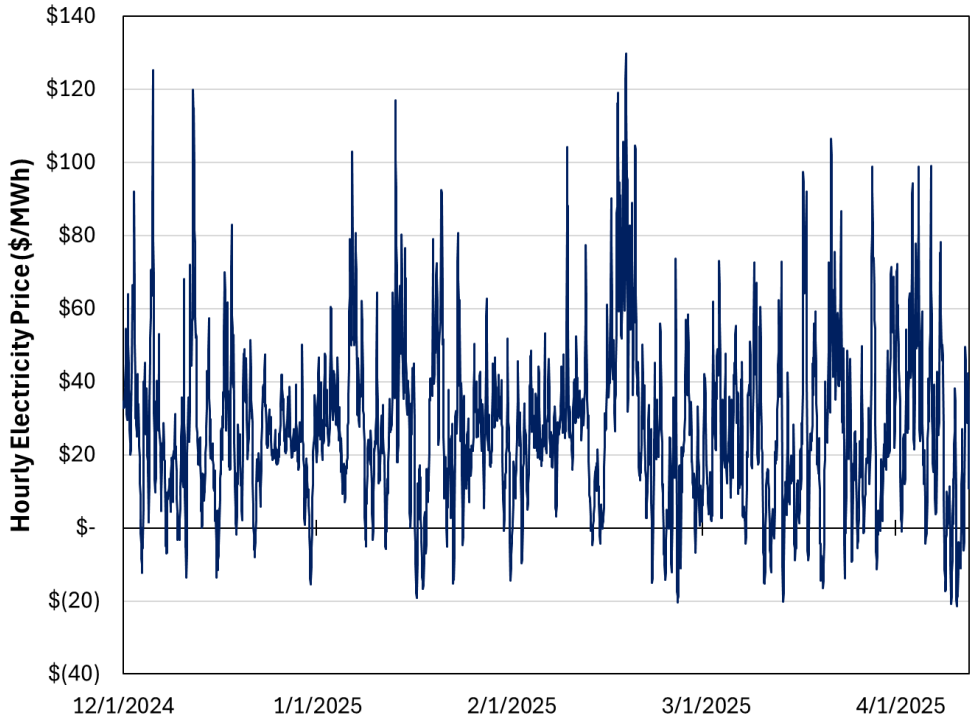
[95] The Winter and Sumer Capacity reflect the seasonal capabilities of the plant whereas the Nameplate represents the maximum possible output.

main driver of revenue. In my calculations, the market price for electricity is based on the actual SPP day-ahead locational marginal price of energy at the OPPD_OPPD settlement location (pricing node: "OPPD_LA") and was derived from daily pricing reports posted by SPP for the period of damages (i.e., December 17, 2024 – April 15, 2025).[96] Since both Turtle Creek and Standing Bear Lake were not operating during this time, a nodal price specific to the plants could not be used. Instead, the OPPD_OPPD price was used as proxy. It is my understanding that the OPPD_OPPD settlement location represents the average settlement price for load in the OPPD area, and is therefore a good representation of the average price that plants in the OPPD area could expect to receive for their power. As a cross-check, I compared the OPPD_OPPD monthly average price to the average price of 10 other pricing nodes in the OPPD area and found that the prices tracked closely, providing additional certainty on the representative price used.

Figure E-2 shows the hourly energy price at the OPPD_OPPD settlement location. By using the actual hourly price that occurred, we can produce an accurate estimate of the price OPPD would have received for its power, which takes into account market impacts like weather conditions, supply and demand.

[96] SPP, Day-Ahead Market, https://portal.spp.org/groups/day-ahead-market

Figure E-2: Historical Hourly LMP at OPPD_OPPD Settlement Point (12/1/24 – 4/15/2025)



E.1.6 Natural Gas Price

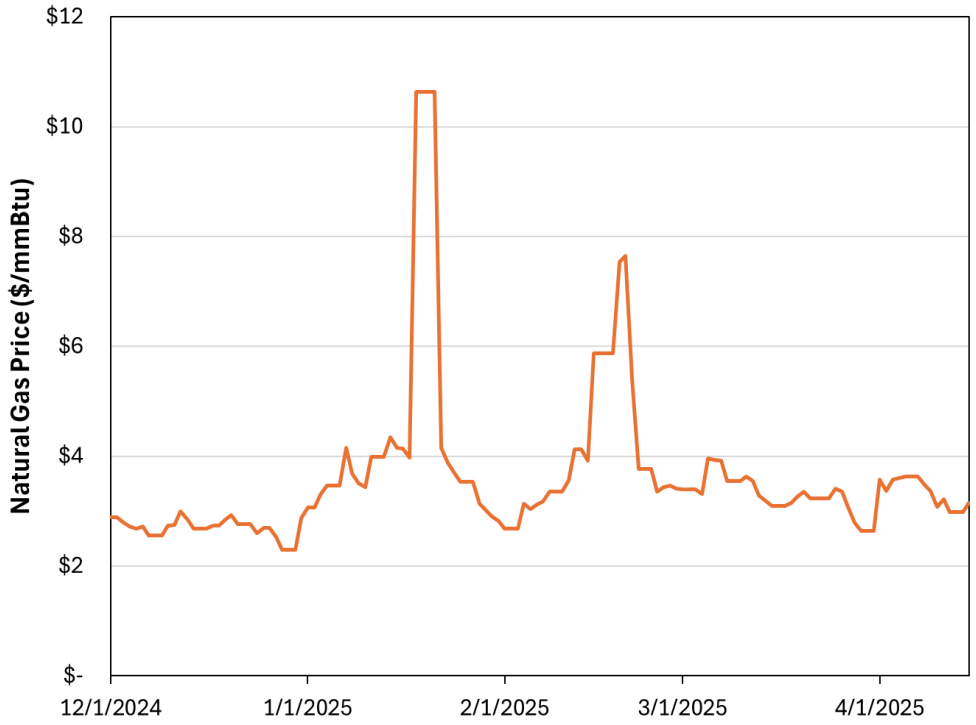
The cost of production is a key component to the estimated damages and for a natural gas peaking plant, the cost of fuel (i.e., natural gas) is the primary driver of that cost. In order to estimate fuel costs, I relied on the actual daily natural gas prices at the Northern Natural Gas Pipeline ("NNG") Demarc Hub for the damages period. The data was sourced from Natural Gas Intelligence and represents the actual daily settlement prices at the pipeline that an generator would expect to see. [97] The daily prices are produced for weekdays only, and therefore for purposes of estimating damages, the price on the last trading day trading was applied to weekends and holidays

[97] Natural Gas Intelligence (NGI), https://naturalgasintel.com/premium/daily-historical-data/

(i.e., the Friday price was applied to Saturday and Sunday).No additional adjustments were made to the daily prices for transportation of fuel from the pipeline to each plant.

Figure E-3 below shows the daily natural gas price that was applied the dispatch model. The daily price is applied to all hours in the associated day.

Figure E-3: Daily Natural Gas Price at NNG Demarc (12/1/2024 – 4/15/2025)



While there are several natural gas pipelines that pass through SPP, the NNG Demarc Hub was selected since it is the closest pipeline and hub to the Facilities.

Additionally, a review of EIA Form 860[98] data on natural gas plants in the OPPD area indicated that plants are purchasing directly from the NNG pipeline or acquiring gas through the

[98] EIA, Form 860, https://www.eia.gov/electricity/data/eia860/

Metropolitan Utilities District ("MUD"), the local utility that operates the drinking water and natural gas system for Omaha.[99] Upon further review of the MUD 2023 Annual Report,[100] MUD signed a 20 year firm transportation agreement with NNG in 2012 for purposes of providing firm natural gas transportation service to plants in the OPPD area. With MUD as the local utility providing natural gas services to the plants, pricing at the NNG Demarc Hub is an appropriate estimate to use for the cost of natural gas that both plants would have expected to see.

E.1.7 Ancillary Services Price

The hourly market clearing prices for ancillary services by product can be found on the SPP website.[101] In order to estimate damages, I apply the hourly SPP clearing prices for Regulation-Down and Spinning Reserves to the capacity of the Facilities on an hourly basis.

Since it is not possible for the Facilities to provide both types of Ancillary Services in a given hour, I adjust my calculations to provide one or the other. When it is economic for the plants to operate based on the hourly electricity price and cost of production, I assume the plants would be providing Regulation-Down services. When the plants are not operating due to economics, I assume the plants would be providing Spinning Reserves. The calculation for each service is listed below:

- **Regulation-Down Damages** = Quantity of the Facilities X Hourly Regulation-Down Price by Season

[99] Metropolitan Utilities District (MUD), About Us, https://www.mudomaha.com/about-us/

[100] MUD, 2023 Annual Report, p. 93, https://www.mudomaha.com/wp-content/uploads/2024/04/RPT_MUD_ANNUAL_2023_FINAL.pdf

[101] SPP, https://portal.spp.org/pages/da-mcp

- **Spinning Reserves Damages** = Quantity of the Facilities X Hourly Spinning Reserves Price by Season

The resulting number is then adjusted to reflect the market share of the plants, in order to estimate the actual portion of reserves that the Facilities would likely contribute to. For reasons discussed earlier in this report, it is assumed the Turtle Creek Station would provide roughly two percent of required quantity and the Standing Bear Lake Station would provide roughly one percent. The ancillary damages are adjusted accordingly.

E.1.8 Capacity Price

During Winter 2024-25, SPP had an excess of capacity and RAR.[102] This is confirmed by the NERC 2024-25 Winter Reliability Assessment which states, "SPP anticipates that planning reserves are adequate for the upcoming winter season."[103] Similarly, SPP has excess capacity through 2026.[104] As a result, the value for capacity would be expected to reflect this excess and be less than the Net CONE of a new combustion turbine unit.

To calculate the estimated damages for capacity, I relied on the Midcontinent Independent System Operator ("MISO") Zone 3 capacity prices for the 2024-25 planning year. The MISO capacity price is separated into a Winter and Spring period, and the clearing prices for

[102] SPP, SPP Projects Confidence in Meeting Energy Needs This Winter, November 19, 2024, https://www.spp.org/news-list/spp-projects-confidence-in-meeting-energy-needs-this-winter/

[103] NERC, "2024-2025 Winter Reliability Assessment," November 2024, p, 18, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf

[104] SPP, 2024 SPP Resource Adequacy Report, https://www.spp.org/documents/71804/2024%20spp%20june%20resource%20adequacy%20report.pdf

each period were applied to relevant months and days in the damages period. The 2024-25 Zone 3 capacity prices were as follows:[105]

- **Winter (December, January, February) =** $0.75 / MW-Day
- **Spring (March, April, May) =** $34.10 / MW-Day

The prices represent a daily capacity price that is then applied to the total megawatts of capacity each plant provides. An example of the December 2024 calculation for the Turtle Creek Station and Standing Bear Lake Station is as follows.

- **Turtle Creek Station December Capacity Value =** $0.75 X 15 Day(s) X 450 MW = $5,062.50
- **Standing Bear Lake Station December Capacity Value =** $0.75 X 1 Day(s) X 150 MW = $112.50

The MISO Zone 3 prices represent a good proxy of the bilateral price for capacity that OPPD may have entered into given its proximity to the OPPD service territory. **Figure E-4** shows the MISO Zone 3 includes the state of Iowa, which borders Nebraska and OPPD.

[105] Midcontinent Independent System Operator (MISO), Planning Resource Auction, Results for Planning Year 2024-25, p. 3, April 25, 2024, https://cdn.misoenergy.org/2024%20PRA%20Results%20Posting%2020240425632665.pdf

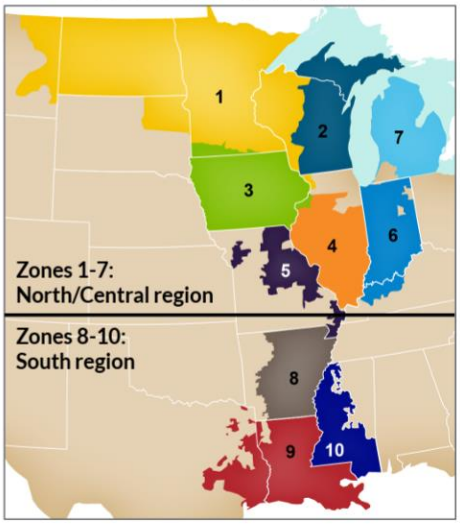
Figure E-4: MISO 2024 PRA Results and Resource Adequacy Zones[106]

2024 PRA Results

Zone	Local Balancing Authorities	Summer	Fall (Price $/MW-Day)	Winter	Spring
1	DPC, GRE, MDU, MP, NSP, OTP, SMP	30.00	15.00	0.75	34.10
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	30.00	15.00	0.75	34.10
3	ALTW, MEC, MPW	30.00	15.00	0.75	34.10
4	AMIL, CWLP, SIPC, GLH	30.00	15.00	0.75	34.10
5	AMMO, CWLD	30.00	719.81	0.75	719.81
6	BREC, CIN, HE, IPL, NIPS, SIGE	30.00	15.00	0.75	34.10
7	CONS, DECO	30.00	15.00	0.75	34.10
8	EAI	30.00	15.00	0.75	34.10
9	CLEC, EES, LAFA, LAGN, LEPA	30.00	15.00	0.75	34.10
10	EMBA, SME	30.00	15.00	0.75	34.10
ERZ	KCPL, OPPD, WAUE (SPP), PJM, OVEC, LGEE, AECI, SPA, TVA	30.00	15.00	0.75	34.10

Highlighted values are CONE pricing

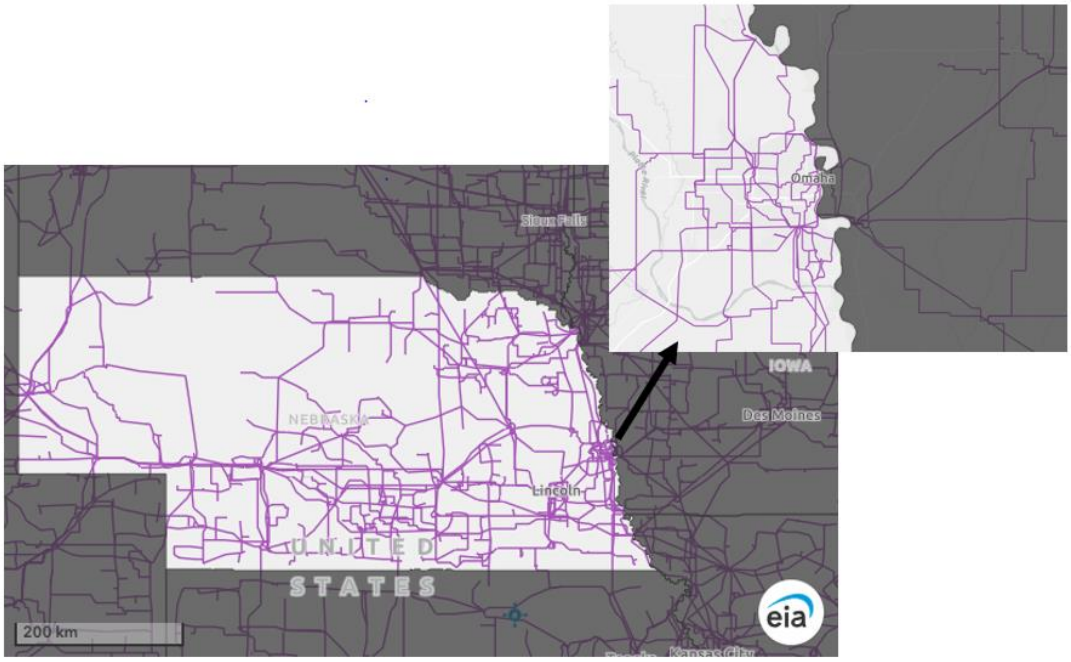
MISO Resource Adequacy Zones



To further support this assumption, I reviewed an electric power transmission map published by the U.S. EIA, which shows 345kv transmission lines directly connecting OPPD to Iowa. Through the use of these lines, OPPD would be able to sell any excess capacity from the Turtle Creek Station and Standing Bear Lake Station directly into the MISO Zone 3. **Figure E-5** provides a zoomed in look at the transmission system connecting the two areas.

[106] Ibid.

Figure E-5: Map of Electric Power Transmission Lines Between Omaha, NE and Iowa[107]

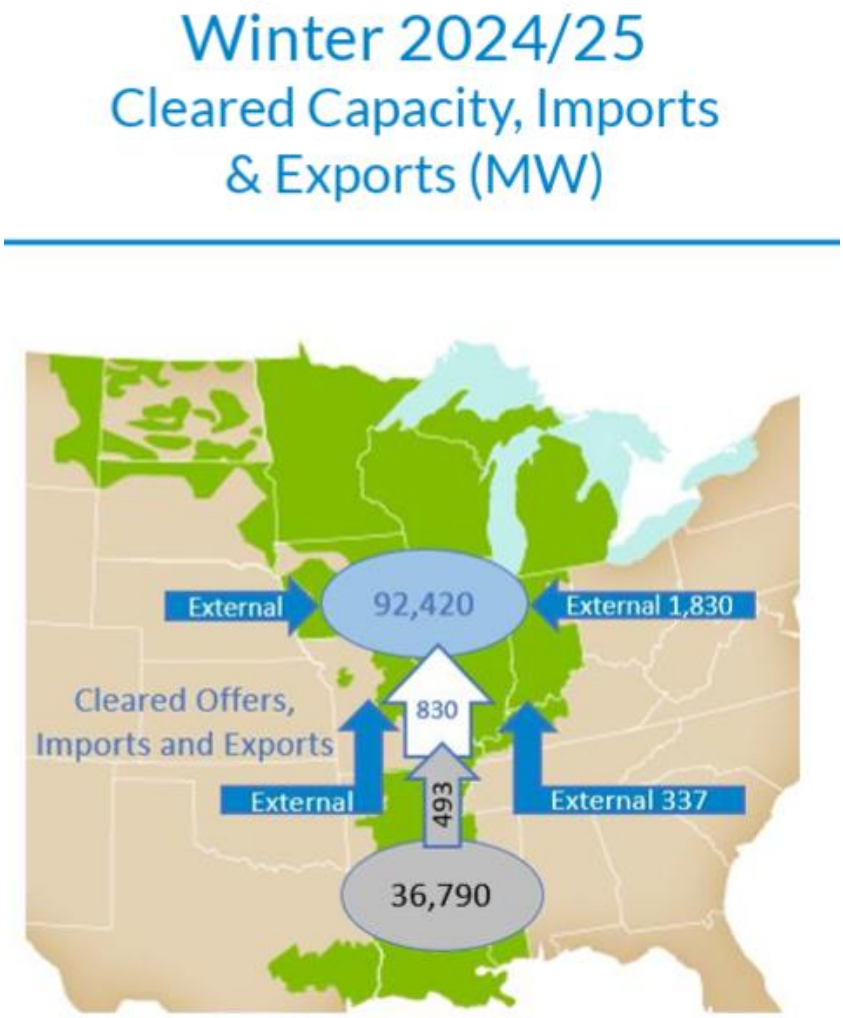


The MISO auction results report also has a map of imports and states the imports by zone for each auction period. Although there are no imports during the winter and spring period into MISO, the interconnections between SPP and MISO link the value of capacity between Nebraska and Iowa (MISO Capacity Zone 3)[108] as illustrated by **Figure E-6**, a chart produced by MISO.

[107] EIA, State Energy Profile, Nebraska, U.S. ENERGY ATLAND WITH TOTAL ENERGY LAYERS, https://www.eia.gov/state/?sid=NE

[108] Capacity Zone 3 has cleared at prices for capacity with the rest of the system. In contrast, Zone 5 has been having capacity price spikes in the Ameren Missouri and Columbia, Missouri;s municipal utility per Ethan Howland, "MISO capacity prices triple for next summer, spring, partly on power plant retirements," Utility Dive, April 26, 2024. https://www.utilitydive.com/news/miso-capacity-pra-auction-missouri/714403/ As Zone 5 is experiencing these capacity price spikes due to insufficient capacity reserves and limited ability to procure such reserves from interconnected markets, these prices are not an appropriate proxy for OPPD.

Figure E-6: MISO Illustration of Potential for Imports into Capacity Markets[109]



As a result, published capacity prices for MISO Zone 3 serve as a market price for the value of the capacity from the Facilities that failed to meet the Guaranteed Substantial Completion Date.

E.2 EX-ANTE PROJECTION AS OF AUGUST 1, 2024

Key inputs used to calculate damages under the ex-ante approach include the following:

[109] MISO, Planning Resource Auction, Results for Planning Year 2024-25, p. 31, April 25, 2024, https://cdn.misoenergy.org/2024%20PRA%20Results%20Posting%2020240425632665.pdf

- Damages Period
- Plant Heat Rate
- Variable O&M
- Quantity
- Energy Price
- Ancillary Services Price
- Capacity Price

There are a number of the assumptions in the ex-ante approach that rely on the same values used in the ex-post approach. This includes the damages period, plant heat rate, variable O&M, quantity, ancillary services price, and capacity price. To avoid duplication, see Section E.1 for details on those assumptions. The remainder of this section provides additional details on each of the assumptions specific to the ex-ante approach.

E.2.1 Energy Price

Unlike the ex-post approach, an electricity price forecast was needed to project damages as of August 1, 2024. I therefore relied on electricity futures prices for monthly SPP North Hub Peak and Off-Peak strips, as provided by the Intercontinental Exchange.[110] The futures represent the estimated prices market participants would expect to see for their electricity at a future date. Prices were pulled as of a July 29, 2024 trade date in order to replicate what prices would have been known as of the August 1, 2024 date (Note: July 29th was the closest trade date to August 1st with available pricing data). The monthly futures prices include both peak and off-peak prices for

[110] Intercontinental Exchange (ICE), https://www.ice.com/index

the "SPP North Hub".[111] The SPP North Hub was selected since it represents the average electricity prices for the northern section of SPP, which encompasses OPPD. Futures on a more granular level, such as the OPPD area, do not exist.

The monthly futures prices were ultimately converted into hourly prices based on historical pricing shapes for the SPP North Hub. The hourly price forecasts were calculated as follows:

- **Monthly Futures Prices:** Futures prices for monthly peak and off-peak strips were pulled from ICE as of a July 29, 2024 trade date for the SPP North Hub.
- **Peak versus Off-Peak Hours:** Hours during the damages period were identified as peak versus off-peak hours according to SPP. Off-peak hours are identified as hours ending 0100-0600, 2300-2400, as well as all weekends and NERC holidays.[112] Peak hours represent the remaining hours.
- **Hourly Ratios:** Actual hourly peak and off-peak LMP prices for the SPP North Hub from 2019 to 2024 are divided by the respective monthly average price for peak and off-peak hours to produce a ratio to shape a monthly futures price.
- **Calculation:** The hourly ratio is applied to the monthly futures price to derive an hourly energy price based on futures and historical shapes.
    - **Peak Hour Prices =** Peak hourly ratio for each hour times peak monthly futures
    - **Off-Peak Hour Prices =** Off-Peak hourly ratio for each hour times off-peak

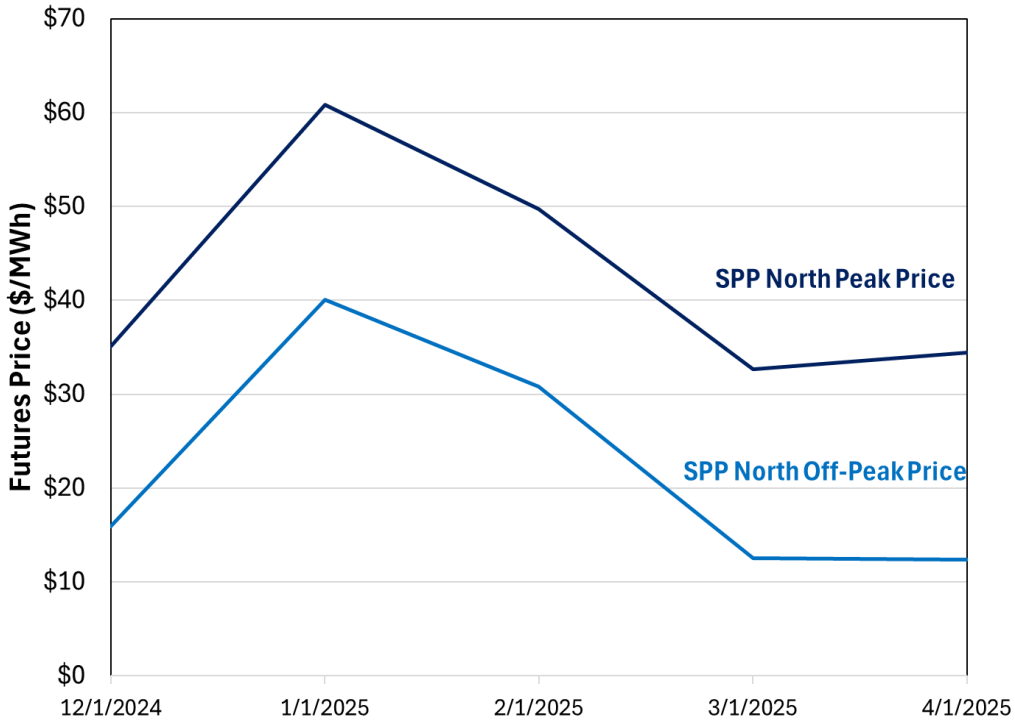
[111] ICE, SPP North Hub Day-Ahead Peak Fixed Price Future, https://www.ice.com/products/31687068/SPP-North-Hub-Day-Ahead-Peak-Fixed-Price-Future; SPP North Hub Day-Ahead Off-Peak Fixed Price Future, https://www.ice.com/products/31687069/SPP-North-Hub-Day-Ahead-Off-Peak-Fixed-Price-Future.

[112] Ibid.

monthly futures

Figure E-7 presents the monthly futures prices for SPP North as of a July 29, 2024 trade date.

Figure E-7: SPP North Peak and SPP North Off-Peak Futures Prices as of 7/29/2024



In order to account for various market conditions, five different historical shapes were calculated for the months covered by the damages calculation. This includes the following:

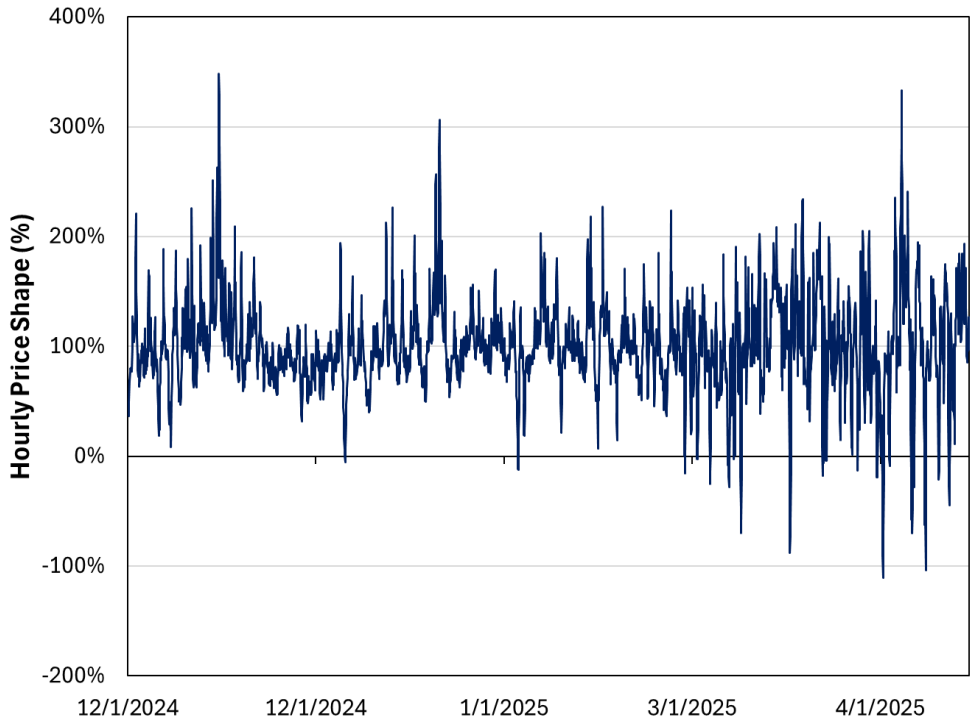
- **Shape 1:** December 2019 to April 2020
- **Shape 2:** December 2020 to April 2021
- **Shape 3:** December 2021 to April 2022
- **Shape 4:** December 2022 to April 2023
- **Shape 5:** December 2023 to April 2024

Each of the five shapes were then applied to the futures prices to generate five different price

forecasts. The forecasts were then run through the dispatch model and the average of the five results was taken.

Figure E-8 presents an example of the hourly shapes using the 2019/20 period.

Figure E-8: Hourly SPP North Price Shape for 2019/20 Scenario



E.2.2 Natural Gas Price

Similar to electricity, a forecasted natural gas price was required under the ex-ante approach. The forecast follows a similar format to that of the forecasted electricity prices, in that it relies on monthly futures strips that are then shaped by historical conditions. In the case of natural gas, monthly settlement strips were pulled from ICE for Henry Hub and the Northern Natural Gas Demarc Basis as of a July 29, 2024 trade date, for the months in the damages period.[113] The NNG

[113] ICE, Henry LD1 Fixed Price Future, https://www.ice.com/products/6590258/henry-ld1-fixed-price-future; NNG

Demarc price represents a basis to the Henry Hub price, which essentially reflects the difference in pricing from the universal pricing hub location (i.e., Henry Hub) to the point of delivery (i.e., NNG Demarc), accounting for variables like delivery costs, pipeline constraints, supply, and demand. The resulting futures price is therefore calculated by adding the Henry Hub futures price to the NNG Demarc basis. The monthly price was then converted into hourly prices based on historical pricing shapes for the NNG Demarc hub.

The hourly price forecasts were calculated as follows:

- **Monthly Futures Prices:** Futures prices were pulled from ICE as of a July 29, 2024 trade date for the Henry Hub and NNG Demarc basis products. The NNG Demarc basis was then added to the Henry Hub price.
- **Daily Ratios:** Daily natural gas prices for the NNG Demarc Hub from 2019 to 2024 are divided by the respective monthly average price to produce a ratio to shape a monthly futures price.
- **Calculation:** The daily ratio is applied to the monthly futures price to derive a daily natural gas price based on futures and historical shapes. The daily price is then converted to hourly by assuming the same price across all hours in the day.

Daily Price = Daily ratio for each day times monthly futures

To account for various market conditions, five different historical shapes were calculated for the months included in the damages calculation. This includes the following:

- **Shape 1:** December 2019 to April 2020

Demarc Basis Future, https://www.ice.com/products/6590131/NNG-Demarc-Basis-Future

- **Shape 2:** December 2020 to April 2021
- **Shape 3:** December 2021 to April 2022
- **Shape 4:** December 2022 to April 2023
- **Shape 5:** December 2023 to April 2024

Each of the five shapes were then applied to the futures prices to generate five different price forecasts. The five price forecasts were then run through the dispatch model and the average of the five results was taken. **Figure E-9** presents an example of the shaped futures using a 2019/20 price shape.

Figure E-9: Hourly Shaped Natural Gas Futures Using a 2019/20 Price Shape

