October 1, 2021

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Highway
Lansing, MI 48917

Re: Cases U-20147, U-21122

> In the matter, on the Commission's own motion, to open a docket for certain regulated electric utilities to file their distribution investment and maintenance plans for other related, uncontested matters.
> Case No. U-20147
>
> In the matter, on the Commission's own motion, to review the response of Alpena Power Company, Consumers Energy Company, DTE Electric Company, Indiana Michigan Power Company, Northern States Power Company, Upper Michigan Energy Resources Corporation, and Upper Peninsula Power Company to recent storm damage in their territories.
> Case No. U-21122

Dear Ms. Felice:

Enclosed for filing in the above-referenced matter, please find the Comments of the Citizens Utility Board of Michigan. If you have any questions, please do not hesitate to contact me.

Sincerely,

Amy Bandyk
Executive Director
Citizens Utility Board of Michigan

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

Case No. U-20147

In the matter, on the Commission's own motion, to open a docket for certain regulated electric utilities to file their distribution investment and maintenance plans and for other related, uncontested matters.

Case No. U-21122

In the matter, on the Commission's own motion, to review the response of Alpena Power Company, Consumers Energy Company, DTE Electric Company, Indiana Michigan Power Company, Northern States Power Company, Upper Michigan Energy Resources Corporation, and Upper Peninsula Power Company to recent storm damage in their territories.

COMMENTS OF THE CITIZENS UTILITY BOARD OF MICHIGAN

The Citizens Utility Board (CUB) of Michigan thanks the Commission for opening this inquest and giving us the opportunity to comment on utility distribution plans and whether they are sufficient to tackle the demanding task of improving electric reliability for Michigan customers.

The Citizens Utility Board (CUB) of Michigan, as a nonprofit residential ratepayer advocate, sees reliability as at the core of utility-customer relationship. But in recent years, Michigan utilities, in general, have not held up their side of the commitments in that relationship. The recent widespread power outages are a concrete example of the trend that has been captured by reliability metrics for years—Michigan utilities are generally well below peer utilities in nearby states and across the United States on most measures of reliability.[1]

Against that backdrop, the investor-owned utilities' distribution plans represent a critical opportunity for the public to review the steps utilities will take to turn around the situation. Because investments into the grid must be planned far in advance, the effects will not be felt for

[1] See U.S. Energy Information Administration statistics compiled and analyzed by CUB in this report: https://www.cubofmichigan.org/utility_performance_report_2020_edition

years. The fate of Michigan's customers—and the hundreds of millions of dollars in costs they collectively pay in the form of economic losses from poor reliability—will be decided by what is done now.

The distribution plans filed this year have many good ideas and show a commitment to invest more into the reliability and resilience of the grid than in years past. But given the aforementioned stakes, CUB argues that the plans could be structured better to include more actionable proposals in several key areas. These comments will address those areas in the context of the questions the Commission asked for stakeholder comment on in the order in U-21122.

We strongly support the Office of Attorney General's comments, particularly regarding the need for more preventative maintenance, more benchmarking reliability performance against peer utilities throughout the industry and the need for a more holistic look at how proposed grid expenditures would affect customer bills.

1. Are the measures focused on improving distribution system reliability identified in the respective distribution plans commensurate with the scale of the challenge?

This question is extremely difficult to answer without the opportunity for searching examination through a contested case. There are many technical questions that span a utility's service territory that must be considered to determine which specific measures can balance cost-effectiveness and progress on reliability.

CUB is concerned that stakeholders will end up exploring these questions in the utilities' next rate cases, where the timelines are tight, there are many issues requiring attention and the scope is largely limited to the projected test year.

Giving an individual utility's distribution plan the full scrutiny it deserves requires numerous steps that are difficult to perform in the context of a rate case where distribution spending is just one piece of the case. There are dozens of other issues that require time spent in the discovery and testimony stages. Some examples of discovery topics that, in a rate case, would be time- and attention-consuming and overly focused on distribution include:

-requests for information about specific portions of the grid, down to the substation level

-requests for information about weather incidents, vegetation patterns and other causes of different types of outages
-detailed examinations of outage causes by grid component, grid component age and condition prior to outage, cause, grid topology location and geographical locations
-issues around equity and justice (as further described later in these comments) that are not directly concerned with the rates that customers pay
-benefit-cost analysis of various grid improvement measures

Nevertheless these are the kind of discovery questions that must be asked to confirm if utility distribution plans are up to the task at hand.

For these reasons, we ask the Commission to examine each utility distribution plan in separate contested cases that are not time-constrained.

2. Are the metrics identified by the utilities to reduce the number and duration of outages and the number of customers experiencing multiple outages appropriate?

No. In the opinion of CUB, the metrics identified by the utilities lack both the specificity and the ambition needed to achieve substantive improvements in reliability.

With respect to specificity, the current statistics are largely system-wide summaries supplemented by information about “worst circuits.” Distribution system investments as described in the plans are broken down by voltage level and major components, such as subtransmission substations, subtransmission lines, distribution substations, primary distribution lines, distribution transformers, secondary lines, and customer services. The available statistics are not diagnostic as to which portions of the grid are contributing to outages, nor do they indicate which customers by class and voltage level are experiencing the outages. As a result, it is nearly impossible to accurately determine the potential benefits of distribution investment programs in either improved outage statistics or in monetized benefits.

Further, the outage cause classifications that are used by utilities are inconsistent (see reporting standards for cooperative utilities adopted by the USDA Rural Utility Service for a good example of such standards). Nor do utilities systematically report the contributions of these causes by grid component in a way that would allow examination of the alignment between outage causes and distribution system investments.

Worst circuits are too coarse to be meaningful. A long circuit with multiple branches may serve hundreds or thousands of customers but may have one segment that is prone to outages, such that the customers on that segment experience many outages but the metrics for the whole circuit are not particularly bad. A far more useful approach is to start with customers who experience unusually frequent outages, look (statistically) for geographical clusters of customers with common outage experiences, and target solutions to those clusters. Alternatively, and useful for equity analyses, outage statistics can be reported on a census tract or zip-code basis, which would approximate the necessary finer geography and also permit comparison to demographic and economic data.

On the question of ambition, goals for achievements on metrics should focus on improvements relative to similarly-situated utilities, not merely on improvements relative to the current baseline for Michigan utilities. That is because the baseline is, for the most part, subpar compared to the reliability experienced by customers in most of the rest of the country. An outcome of these plans could be that utility service becomes marginally more reliable than it is today, while still being well below average compared to utilities in other states. Marginal improvements from a low bar should not be the goal of this proceeding.

For example, in Consumers Energy's plan, the utility targets reducing CAIDI (without major event days) from the baseline of 196 minutes to 179 minutes by 2025. But even if that goal was achieved, Consumers Energy would still be well above the national median in 2018 of 107 minutes and the regional average of 120 minutes.[2] Similarly, the utility's target of 170 minutes for SAIDI by 2025 is above the national median of 118 and the regional average of 119.5.

DTE's EDIIP, meanwhile, has no targets for SAIDI/CAIDI after 2020.

We understand that, given the fact that the effects of reliability improvements tend to be lagging, it may be unrealistic to expect reliability indicators to improve to the level of industry averages or medians in a mere five years. At the same time, however, the Commission and the Company should not lose sight that the goal is to build electric reliability up to acceptable levels, not to simply make any marginal progress from the current poor state of affairs. To that end, in their distribution plans, utilities should report the timeline at which they believe they can achieve SAIDI/CAIDI/SAIFI performance that is within a reasonable range of median and averages for utilities in neighboring states, based on EIA data.

[2] These figures are EIA data as compiled in CUB's Utility Performance Report from 2020. "Regional average" is the average score for Michigan plus the neighboring states of Ohio, Indiana, Illinois, Wisconsin and Minnesota.

3. Do the financial incentives and penalties identified by the utilities align the respective utility's financial goals with the goals of this Commission in reducing outages and improving distribution performance?

No. While both DTE and Consumers Energy's plans lay out potentially useful sketches for how an incentive/penalty design could practically work (see DTE's Exhibit 15.3.2 and Consumers Energy's Figure 8) their plans are for the most part vague about the exact nature of a potential incentive/penalty. Both DTE and Consumers Energy suggests that an incentive/penalty of an unspecified dollar amount be applied to an increase/decrease in a reliability metric beyond a certain standard deviation threshold. CUB has already laid out a more detailed proposal for a penalty that reflects the actual economic cost of outages.[3]

The idea is simple: academic research finds that the economic cost of outages for residential customers roughly corresponds to $2 per hour. Customers should be eligible for a bill credit of at least $2 per hour. The utility should be able to recover the costs of these credits only to the level that would be expected based on national average performance. CUB's comments in U-20629 give more detail on how the amount eligible for cost recovery could be calculated:

> We propose that rates be set based on an assumption that the utility recovers bill credits with a value of $2 multiplied by the national average SAIDI. To be clear, the actual payout for bill credits would still be $2 per hour. But if, for example, the national average SAIDI is 150 minutes, or 2.5 hours, then rates would include the assumption that the utility is recovering bill credits of $5 per customer per year. The utility would fully recover their costs if its average SAIDI was 150 minutes. If the utility's SAIDI is less than the average, then the utility is essentially able to earn an extra return. For example, if the utility's SAIDI was less than 120 minutes, it would be charging ratepayers as if the credit was $5, but only paying out an average of $4 per customer, giving a rate of return from an extra $1 per customer. If the utility's SAIDI was worse than the national average, the payment of bill credits would function as a penalty.
> The result is that the utility has a financial incentive to improve the average number of minutes of outage per customer.

There are two main advantages of our bill credit proposal over the utilities' suggestion based around standard deviations.

[3] See CUB's comments filed Jan. 27, 2020, U-20629-0024, as well as our report, Utility Regulatory Measures to Improve Electric Reliability in Michigan - March 2020.

First, our proposal recognizes that we cannot judge whether reliability is improving at satisfactory levels without making comparisons to other jurisdictions. Both Consumers Energy and DTE propose that outage reductions should be judged based on statistically significant differences from past performance. A decrease in SAIDI relative to previous average performance by the utility falls into the trap of the “soft bigotry of low expectations”—the utility can reap financial rewards from marginal progress while reliability is still poor by any objective measure. The way to avoid this trap is to tie financial incentives and disincentives to performance relative to a peer group.

Second, our proposal ties utility performance not to a statistical abstraction like the standard deviation, but to the economic value of power outages. Doing so aligns the costs incurred by customers from power outages to the costs of reliability measures taken by the utility. Consider: if the utility’s reliability efforts fall short, customers receive compensation for the hardship they endure. But If the utility meets its goals, the avoided bill credits due to fewer and shorter-duration outages help finance the spending on the successful reliability measures.

A flaw in this proposal is that $2 per hour is only an approximation of the cost of economic outages, which is very hard to precisely measure. So it is not really the case that bill credits fully compensate the customer. But our proposal would at least take steps toward aligning spending on reliability measures with the costs of outages, making it superior to the alternative put forth by Consumers Energy and DTE.

Another important consideration is that a utility that improves reliability by investing capital increases its returns to shareholders as a result. This provides an incentive to focus on solutions that require investment rather than maintenance. For example, it seems well established that vegetation management provides far more cost-effective improvements in reliability than does grid capital investment. In the distribution plans submitted by Michigan utilities, most of the projected improvements in outage rates are due to improved vegetation management. Nonetheless, the plans call for far more spending on grid capital investments than on vegetation management. Incentives for improved performance should not be designed to provide even greater returns on investment than the Commission allows in rate-making, but to ensure that the utility is motivated to cost-effectively improve reliability. CUB’s proposal to use bill credits that reasonably approximate the customer costs of outages helps to address this need in two ways. First, because the utility is incentivized to minimize credits in the short term, it is incentivized to target maintenance and investments on those locations that will most cost-effectively reduce bill credits. Second, because the bill credits CUB recommends are based on the customer cost of outages, the cost-effectiveness of a proposed expenditure by the utility can be directly evaluated by comparing the cost of the expenditure to the avoided cost of bill credits that were not paid out due to the reduction in outages attributed to the expenditure.

4. Do the distribution plans filed reflect the appropriate balance between needed investments and customer affordability? Are there alternatives that would better strike this balance?

There are at least two first steps the Commission could take to place customer affordability at the center of the distribution plans.

First, the distribution plans should be required to more explicitly evaluate the tradeoff between dollars invested and reliability gains, as measured by SAIDI, CAIDI and SAIFI. Doing so would allow the Commission and stakeholders to judge whether or not ratepayer dollars are being directed to where they will get the most return. For example, Figures 5 and 6 in Consumers Energy's plan show the estimated reductions in SAIFI and CAIDI for various investments and activities. A similar table that shows these reductions presented as per dollar invested would be very helpful for all parties' abilities to evaluate these plans.

Second, the utilities' distribution plans are primarily built around responding to problems—a piece of equipment reaches the end of its useful life, so it needs to be replaced. A tree has overgrown its purchase and so it needs to be cut. A disruption has occurred and so part of a circuit needs to be isolated. Being able to respond in a quick and coordinated fashion to problems that arise is very important, especially because it is inevitable that problems will appear without warning. But an ideal distribution plan would be able to detect and prevent these problems before they occur to the greatest extent possible.

Those kinds of proactive measures have, for the most part, not been pursued by Michigan utilities, and the distribution plans being considered now do not significantly change that pattern.

The comments filed by the Office of the Attorney General in this proceeding has several suggestions for how the utilities can pursue additional preventative maintenance measures. We support those comments, and also below add some additional suggestions.

In testimony filed in Consumers Energy's electric rate case U-20963[4], 5 Lakes Energy Senior Consultant Rob Ozar explained how researchers have developed "Distribution Fault Anticipation Technology" [DFA] software that allows a utility to automatically detect "upstream" conditions that can lead to downstream reliability events. Mr. Ozar explained the significant advantages

[4] We summarized Mr. Ozar's testimony on CUB's blog: https://www.cubofmichigan.org/more_spending_on_the_grid_means_better_power_not_always

that this approach has over the routine monitoring that utilities currently conduct in order to detect problems before they occur.

> "However, because the Company's distribution system monitoring occurs on a scheduled basis, with significant time periods in between asset evaluations, it has an obvious inherent limitation," Ozar said. "It is incapable of flagging incipient adverse conditions that occur in the interim between the scheduled monitoring. Decreasing the timespan between scheduled monitoring, under this paradigm, could improve asset evaluation but cannot eliminate this limitation."

The investments in technology laid out in the utility distribution plans do not contemplate this level of sophistication. DTE plans to increase spending on sensing and monitoring techniques like smart fault indicators and line sensors, and while useful, this equipment is meant to detect problems once they are already occurring, not to allow the utility to get ahead of problems. Consumers Energy's plan similarly does not contemplate the technology discussed by Mr. Ozar.

Indiana Michigan Power's plan describes "AMI, Enhanced CVR, Sensors, DACR and Smart Reclosers" as "technologies that will help it monitor, protect, and improve the operation and resiliency of its distribution system." We do not dispute this statement at all, but would add that as helpful as those technologies are, DFA brings a whole new level of sophistication by using machine learning to constantly improve predictive capabilities. As such, DFA could provide I&M and other utilities a significant enhancement in its ability to monitor outages above and beyond the technologies mentioned above.

The utilities should pursue DFA pilot programs in order to begin integrating more proactive strategies into their distribution plans. While these pilots will need to be approved by the Commission in separate proceedings, the distribution plans should set aside space to consider how DFA might interact with other strategies and potentially make some amount of traditional distribution spending unnecessary.

5. Do the distribution plans sufficiently incorporate considerations involving equity, including efforts to avoid further marginalization of vulnerable customers and communities?

Older, less economically-advantaged communities appear to suffer from the worst reliability (though the extent of this inequity cannot be quantified due to the lack of geographical detail in outage statistics) and also have the least means to cope with the loss of basic goods stemming from power outages, so this equity consideration is extremely important. The section of DTE's plan on energy and environmental justice, in which the company explores overlaying data on socioeconomic indicators with reliability data across the utility's service territory, is something that all Michigan utilities should be considering in their distribution plans.

There are likely two causes of systemic inequity in customer outage experiences. One is that beginning in 1974, most new distribution system extensions were placed underground, a practice that tends to reduce the number of outages. Low-income customers and minority populations tend to live in older housing that have overhead distribution systems. Nonetheless, they pay the same rates for power delivery as those in the new areas with better reliability. The system of credits CUB has proposed has the merit of reducing the utility bills of those who experience outages, which should partially offset this inequity. Further, as outlined above, a utility that is motivated to reduce bill credits can then focus its attention on these older, less reliable portions of the distribution system.

We also suggest that distribution plans consider how growth in their service territories exacerbates inequities in reliable electric service. New growth areas, which also tend to be more affluent than average, receive investments into distribution capacity that further improves the reliability of their local grid compared to older, non-growing areas that receive investment when equipment fails. In order to compensate for this built-in bias that contributes to unequal reliability across service territories, distribution plans should contemplate directing additional resources into monitoring and repairing the grid in older, marginalized communities.

Current utility practices actually in some cases subsidize new infrastructure for more affluent, high-growth portions of the service territory while poorer areas that suffer worse reliability, pay for these subsidies in their rates. Testimony[5] filed in U-20561 in 2019 on behalf of CUB and other groups explains how for DTE, the amount of Connection and New Load expenditures covered by customer advances in accordance with Contribution in Aid of Construction (CIAC) leads to cross-subsidies from customers with a high ratio of distribution revenue to total revenue to those with a low ratio. On net, DTE is experiencing load declines, so the Connection and New Load expenditures are essentially a redistribution of load to these more affluent areas, and that redistribution is subsidized by all customers.

The testimony suggests ways to reform CIAC to eliminate these cross-subsidies. These courses of action should be part of utility distribution plans because they would free up more resources to be used to enhance reliability in areas with disproportionately worse utility performance.

[5] U-20561-3048, Dec. 10, 2019. Pages 18-25.

6. Are there potential utility pilots or industry best practices that can improve customer safety and reliability by moving overhead lines on specific circuits or in segments of the electric distribution system underground at reasonable costs?

We do not have any comments on this question at this time.