BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

REVIEW OF STORM PROTECTION PLAN, PURSUANT TO RULE 25-6.030, F.A.C., DUKE ENERGY FLORIDA, LLC.

DOCKET NO. 20220050-EI

REBUTTAL TESTIMONY OF AMY HOWE

ON BEHALF OF DUKE ENERGY FLORIDA, LLC

JUNE 30, 2022

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is Amy M. Howe. My current business address is 13338 Interlaken Road, Odessa, FL 33556.

Q. Have you previously filed direct testimony in this docket?

A. Yes, I filed direct testimony supporting the Company's SPP on April 11, 2022.

Q. Has your employment status and job responsibilities remained the same since discussed in your previous testimony?

A. Yes.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to provide the Company's rebuttal to assertions and conclusions regarding the Transmission specific aspects of DEF's 2023-2032 Storm Protection Plan ("SPP 2023" or "Plan") contained in the direct testimonies of OPC's witnesses Kollen and Mara. Mr. Lloyd and Mr. Menendez will present additional rebuttal of the testimonies of OPC's witnesses.

Q. Do you have any exhibits to your testimony?

A. No.

Q. Please summarize your testimony.

A. My testimony focuses on Witness Mara's and Witness Kollen's testimonies as they relate to Transmission-specific programs and subprograms and rebut the misinformation and incorrect conclusions contained within. In sum, when the Transmission programs are properly understood as an integral part of the overall Plan, which is designed as a holistic approach intended to meet the objectives identified by the legislature in section 366.96 (the "SPP Statute"), it is clear the programs are properly included in the Company's SPP and should be approved. OPC's witnesses' arguments to the contrary demonstrate a lack of understanding of the programs themselves and are based on a narrow interpretation of Rule 25-6.030 (the "SPP Rule") that, in DEF's belief, unnecessarily curtails the scope of the SPP contrary to the legislature's intent. Their testimony should be rejected by the Commission.

Q. In general, do you agree with the overall concerns and points of disagreement with Witness Mara's and Kollen's testimonies expressed by Mr. Lloyd?

A. Yes. I have reviewed Mr. Lloyd's testimony and I completely agree with his general concerns and points regarding Mr. Mara's and Mr. Kollen's novel interpretations of the SPP Statute and Rule and note that many of Mr. Lloyd's points apply with equal force to the transmission programs as they do the customer delivery (distribution) level programs, so I will not repeat those points here. I will therefore limit my points of rebuttal to transmission-specific issues. Additionally, Mr. Menendez provides the Company's rebuttal of ratemaking related concerns, which is an area outside of my responsibility, so I express no opinion on those matters.

Q. Mr. Kollen contends that each SPP Project should pass a cost-effectiveness test as a condition of being included in the SPP. Based on your knowledge of the transmission system, is there any reason why such a test would be problematic?

A. Yes, my concern is, due to the configuration of the transmission system, Mr. Kollen's test would potentially exclude many transmission projects thereby limiting the effectiveness of transmission programs. Within the Guidehouse model, if Bulk Electric System ("BES") lines or substations were not directly serving our customers, the customer count was reflected as zero (0) which may contribute to a benefit to cost ratio of less than 100%. In other scenarios, if there were several lines serving a substation the customer count may have been shown as zero (0) on those lines due to the inherent redundancy of the system and again that would likely contribute to a benefit to cost ratio of less than 100%, and the same is true for a tapped line to serve wholesale customers would reflect zero (0) retail customers even though the tapped lines are generally served from the same lines that serve substations with retail customers (i.e., daisy chained, which I will describe in more detail further down in my testimony). In most cases, when a tapped line experiences an outage, the full transmission line is interrupted until the faulted section can be isolated and repaired, hence, tapped lines need to be hardened.

It is essential that the Transmission system configuration is taken into consideration. The transmission system is an integrated grid and therefore upgrading only a portion will not provide the full effectiveness of a program to our customers. Limiting programs to only hardening facilities with a benefit to cost ratio of greater than 100% would be shortsighted and would exclude the BES transmission facilities as well as other facilities that do not directly serve our retail customers although they are critical to the overall Transmission grid.

Q: Are there any other reasons why the configuration of the transmission system is a relevant consideration?

A: Yes. The transmission and distribution systems are integrated and work together to serve our customers. Many industrial and wholesale customers receive electric service straight from the transmission system, specifically at 69kV, which means that any upgrades to the transmission system will directly increase continuity of service and improve overall reliability for those customers. Additionally, service for all customers originates from the transmission system (which acts as a bridge between the generation and the distribution system); therefore, any upgrades to the transmission system will have a positive impact on the overall level of service provided to our customers even if, as described above, due to redundancy reasons a given line is shown as “serving” zero (0) customers.

The BES is the highest voltage portion of the transmission system, consisting of transmission lines and equipment operating above 100kV and serving to transmit large amounts of power throughout the system. The BES is subjected to mandatory reliability standards published and administered by the North American Electric Reliability Council ("NERC") under the authority of the Federal Energy Regulatory Commission ("FERC"). These standards require sufficient redundancy within the BES to allow continued operation even when one or more elements of the system is out of service.

That said, most of DEF's BES assets do not directly serve customers but instead serve as critical infrastructure maintaining power flow within and between DEF, neighboring utilities, and Independent Power Producers.

As a result, failure of a single BES element will often not cause a direct outage to our customers but removes a level of redundancy for the entire BES. Sequential failures within the system can cause significant disruption to power flows and cause extensive customer interruptions as could occur during extreme weather events and therefore it is critical to harden these facilities for extreme weather events and to reliably serve our customers. The BES transmission system is the linkage between the generation facilities to our 69kV system and distribution system that ultimately serves our customers' homes and businesses. Thus, although strengthening the BES may not have a direct impact or quantifiable reduction to customer outages due to the inherent redundancy of the BES, it is a critical component to reliably serving our customers and as such it would defy all logic and sound planning to deny DEF (or any utility) the ability to include such hardening programs and projects in an SPP intended to strengthen the grid as a whole based on an artificial cost-benefit standard that has no support in either the governing statute or rule.

The 69kV transmission lines and equipment are not considered a part of the BES but are transmission lines that deliver power to many of the distribution substations. The level of redundancy, or in this scenario alternate sources, in the 69kV portion of the transmission system, and its ability to withstand an outage of an element of the system without resulting in customer outages, is different from the higher voltage lines within the BES.

DEF's 69kV lines typically run from a circuit breaker in one source substation to a circuit breaker in another source substation, with several distribution substations fed along the circuit in a "daisy chain" fashion. These two sources to the circuit provide a certain level of redundancy. A fault within a segment of such a 69kV line will often result in an outage to the substations and distribution circuits between the circuit breakers, until the faulted section can be identified and the switches along the line opened or closed to isolate the faulted section and restore power to the substations from the un-faulted portions of the circuit.

Q. At the outset, do you have any over-arching concerns with OPC's position in this docket?

A. Yes, I do. I agree with Witness Lloyd in that, while I am not a lawyer (though I note that neither of OPC's witnesses are lawyers either), it appears to DEF that their interpretation of the SPP Statute and Rule is very constricted by limiting SPP eligibility to projects and programs that both decrease outage restoration costs and outages/outage duration. Specific to transmission, the included programs contribute to the systematic nature of the overall Plan that accomplishes these goals, over time, in a cost-effective manner; however, not every program and/or subprogram is intended to reduce *both* restoration costs and outage times. For example, Structure Hardening in its entirety is focused on reduction of outage times and restoration costs, however, the primary benefit of the Gang Operated Air Break ("GOAB") sub-program is reduction of outage times. Of course, by reducing the outage time and sectionalizing the facilities impacted by the extreme weather event inherently there are restoration cost savings that are hard to quantify. That said, DEF simply cannot agree that either the Legislature or Commission intended to exclude any project or program (or sub-program) from inclusion in the Plan because it does not, on its own, accomplish each of the goals identified in the SPP statute and rule.

Q. Have you fully described the transmission programs within the SPP?

A. Yes. The transmission programs have been described in Witness Lloyd's Exhibit BML-1 – Program Descriptions, and further explained in my previously filed direct testimony. In this rebuttal testimony, I will only address the specific contentions raised by OPC's witnesses.

Q. Do the transmission programs put forward under DEF'S SPP meet the requirements of Rule 25-6.030, F.A.C.?

A. Yes, in fact they are the same programs that are included in DEF's currently approved SPP.

Q. In Witness Mara's testimony, he opines that not all of DEF's Storm Protection Plan Programs should be approved by the Florida Public Service Commission. Do you agree with Witness Mara's opinion?

A. No, I do not agree with Witness Mara's opinion; I believe all programs DEF included in its SPP should be approved as they all contribute to the overall efficacy of the Plan. The Plan DEF submitted meets the requirements of the Statute and Rule as it will reduce restoration costs and reduce outage durations during extreme weather events; it does so through a suite of programs that each play a part in achieving the Plan's goals. I will address why I disagree with Witness Mara's opinion regarding each Transmission program and subprogram he discussed and further explain how they meet the requirements of Rule 25-6.030.

Q. Mr. Mara contends the SPP rule requires programs to increase asset strength beyond the original design of the asset being replaced. Do you agree?

A. No, that is not my understanding. While I agree programs that increase strength beyond original design would certainly qualify for the SPP, I am not aware of any such limitation in the Statute or Rule, nor has either of OPC's witnesses cited one. As I understand the Statute and Rule, SPP programs and projects are intended to protect and enhance the system for the purposes of reducing restoration costs, reducing outage times, and improving overall service reliability. Again, though I am not an attorney, it seems logical and consistent with the SPP's goals to include enhancements that, while they may not strengthen facilities relative to the original design, work to arrest the natural weakening or deterioration of those assets, thereby preserving the strength of the facilities so they can better resist the impacts of extreme weather conditions. To DEF, this is a cost-effective means of enhancing the system that will provide real benefits to our customers (as opposed to, for example, simply replacing all transmission facilities).

Examples of sub-programs that protect the strength of the Transmission system and are projected to reduce outage times and restoration costs resulting from extreme weather are Cathodic Protection and Replacing Overhead Ground Wire.

Below, I will further describe both cathodic protection and OHGW subprograms within the Structure Hardening program and how they meet the objectives of the rule as important components of a comprehensive Plan.

Q. Witness Mara states that "hardening means to design and build components to a strength that would not normally be required" and that "aging infrastructure" should not be replaced as part of the Storm Protection Plan. Do you agree with Witness Mara's statement?

A. No, I cannot agree with that assertion because it simply ignores the reality of operating a utility system. Obviously, our system is exposed to the elements all the time, and in Florida those elements can be brutal on utility infrastructure. As a result, "aging" infrastructure not yet at the end of its expected life and therefore still accomplishing its purpose could be replaced with a new component that will simply perform better, thereby strengthening the overall system relative to the status quo, which I believe is the goal of the SPP. A program that includes such replacements (for example, structure hardening and the overhead ground wire replacement sub-program I will discuss later) is properly included in the Plan. To the extent OPC's position relative to inclusion of these types of programs within the SPP is based on cost-recovery concerns (i.e., double recovery of costs in base rates and through the SPPCRC), those concerns are addressed by Mr. Menendez's rebuttal testimony.

Q. Would you agree with Witness Mara's conclusions relative to transmission construction using the NESC (National Electric Safety Code)?

A. On page 7 of Witness Mara's testimony, he states specifically relative to transmission poles: "In transmission system hardening, many utilities are using non-wood poles (steel or concrete) to replace existing wood poles. The upgrade to non-wood poles is not required by the NESC but these non-wood poles have proven to reduce outages and reduce outage times due to the superior ability of the non-wood poles to survive during extreme windstorms." DEF agrees that conversion from wood to non-wood poles has proven to reduce outages and outage times and meets the requirement of the Rule. In fact, all the costs proposed in DEF's SPP related to transmission poles are to replace wood poles with non-wood poles, so Mr. Mara agrees that those costs are properly recoverable under the SPP.

Q. Do you agree with Mr. Mara's assertion that the lattice tower replacement subprogram should be eliminated from the plan?

A. No, absolutely not, nor do I agree with any of the points Mr. Mara relies on in reaching his conclusion. First, Mr. Mara stated "Transmission lines have been required by the NESC to be built for extreme wind events since at least 1977. Failure due to design flaw should not be a SPP activity."[1] However, Mr. Mara chose to ignore, or possibly did not know because he failed to ask, that the lattice towers in question predate 1977, therefore there was no NESC required extreme wind loading standard at the time (by his own admission) and the towers did not suffer from a "design flaw" any more than any component that has been updated over time (or which was built to a given standard that has been subsequently modified). Thus, this support for his conclusion fails.

He continues, "If DEF owns towers that fail to meet strength requirements when constructed, then replacement costs should not be considered an 'upgrade' and therefore should not be funded through the SPP."[2] It is irrelevant whether DEF agrees with this general proposition or not, as Mr. Mara offers it without identifying any such towers, he believes failed to meet strength requirements when constructed. To DEF's knowledge, no such towers exist, nor does he opine that the design *was* flawed, but merely states "if" it was flawed it should not have been accepted and thus cannot be a proper SPP program (again, with no support). Thus, this contention likewise fails.

Mr. Mara's next attempt at supporting his conclusion fares no better as it is simply a repeat of his contention that a program that replaces aging infrastructure should be excluded, though this time stated as an accepted fact rather than a dubious proposition.[3]

Mr. Mara next claims "Replacing towers with new towers that meet the same weather loading condition will not add to resiliency. Rather it simply maintains the status quo in terms of strength." As discussed generally above, this argument ignores reality by seeming

[1] Mara Testimony, pg. 28, ll. 20-22.
[2] *Id.* at pg. 28, l. 22 – pg. 29, l. 2; *see also id*. at pg. 29, ll. 6-7 ("If the tower design was flawed, it would have been imprudent for DEF to accept the design and construction of the tower in which case the cost should also be excluded from the SPP.").
[3] *See id.* at p. 29 ll. 2-4.

to believe that the resiliency of the system is somehow a static measure that does not change over time, and that somehow a piece of infrastructure should rationally be expected to retain all its strength throughout its service life. While I wish that were the case, it simply is not. In the real world, accelerated change outs of aging infrastructure increases resiliency and reliability as there would be less infrastructure damaged during an extreme weather event, resulting in fewer failures to mitigate and quicker restoration time for DEF customers. Moreover, Mr. Mara fails to recognize that Tower Upgrades are designed to the latest NESC code, which is updated in 5 years cycles. Equipment standards, both internal and external, are continuously reviewed and updated. Thus, new equipment installations include the improvements as part of DEF's updated standards, meaning the towers are not being replaced "like for like" at all.

This subprogram is proper and should be retained.

Q. Witness Mara asserts that deteriorated overhead ground wire is simply an aging infrastructure the replacement of which does not increase strength. Can you please explain what was meant in your testimony by the term deteriorated OHGW and why the subprogram is appropriate for SPP?

A. Yes, but first I would reiterate my points above that programs or subprograms intended to replace aging infrastructure that are not functioning to the level they did when originally installed due to the passage of time and/or because they have simply been performing as designed but cannot realistically be expected to do so indefinitely, are properly included in the SPP.

With that said, Deteriorated Overhead Ground Wire ("OHGW") is static conductor that has lost some of its strength but still performs the designed function, albeit at reduced capacity. Overhead static wire deterioration occurs when the protective galvanization has been sacrificed and static in this condition is more prone to failure. It is known and accepted that all static sizes and material combinations will lose their galvanization and eventually rust, thus reaching the end of life. Not only is the static more susceptible to failure from both wind and lightning events, but the grounding qualities become compromised. Therefore, the OHGW is not "deteriorated" in the sense of having been poorly designed or maintained; rather, it is simply an asset that, if replaced, will strengthen and better protect the system against the effects of extreme weather relative to the state of the system as it exists today. The OHGW is a contributor to CMI and restoration costs during extreme weather events and therefore, its enhancement serves to strengthen the system as intended by the SPP statute and rule.

Q. The Gang Operated Air Break ("GOAB") Line Switch Automation subprogram was addressed by Witness Mara as a subprogram that should not qualify for the Storm Protection Plan as it does not reduce the restoration costs. Do you agree with his assessment?

A. No, I do not agree with Witness Mara's assessment. As stated in Witness Lloyd's testimony, "From DEF's perspective, the Legislature directed the utilities to develop integrated storm protection plans that as a whole are intended to achieve the goals of reducing restoration costs and outage times to customers and improving overall service reliability. DEF's Storm Protection Plan is the sum of its parts with the programs working together to reduce restoration costs and outages times associated with extreme weather events." The GOAB subprogram is a piece of the overall Structure Hardening program that promotes minimal outage time by providing the ability to perform remote sectionalizing to restore the customer. It also provides relay information on the location of the event. Logically, the time for a crew to patrol the line is reduced and in turn, the cause of the event can be addressed without additional outage time to customers. The benefit of greatly reducing the outage time for our customers should not be discounted. In some of DEF's remote areas, this could reduce from hours to minutes to resolve the outage. Minimizing outage time also effectively manages overall cost required to address the cause of the event. Thus, it is DEF's position that the GOAB subprogram has multiple benefits and is a part of the overall reduction in restoration costs projected from the Structure Hardening program.

Q. Mr. Mara contends that the Cathodic Protection subprogram within the Transmission Structure Hardening Program should be excluded from the Plan because it does not increase strength or improve resiliency. Do you agree?

A. No, I do not agree. As discussed above, I think a subprogram that arrests the natural degradation of a component, thereby maintaining its strength for a greater period of time, makes the asset more resistant to the effect of extreme weather and therefore makes the system as a whole more resilient. The Cathodic Protection sub-program meets the requirements of Rule 25-6.030 through the mitigation of the degradation to structure capacity from groundline corrosion and systematic identification of structures that need kitting or replacement. This program aims to cost effectively address corrosion issues across the entire DEF lattice fleet without prematurely replacing the assets, which directly provides reliability benefits by preserving overall system strength on a larger scale than individual asset change-out. The program also installs reinforcement kits on structures with existing groundline corrosion that are in otherwise good health. As Witness Mara correctly notes "When the strength of a tower or structure decays below a certain level, per the NESC, the structure must be replaced or rehabilitated." Restoring groundline capacity of the structure allows the structure to perform as originally designed for a greater period of time at a fraction of the cost to customers compared to structure replacement. In the end, this subprogram reduces restoration time after major storms through verification and preservation of DEF's lattice towers system health, and through mitigation of existing vulnerabilities from ground line corrosion. As a result, I recommend that this sub-program be included in the SPP.

Q. Mr. Mara recommends excluding portions of the Transmission Substation Flood Mitigation Program. Do you agree with his contentions regarding the need for the challenged aspects of the program?

A. No, I do not. First, I would note that all substations were built to the existing standards in the year they were installed. Witness Mara asserts that: "substations built after 1973 should have been designed with the knowledge of potential flood waters and designs should have accounted for this predictable occurrence." The SPP Flood Mitigation program is directed to the substations at the highest risk of flooding per the most current 100-Year Federal Emergency Management Agency ("FEMA") flood plain, which is under continuous review and updated as needed. For example, the FEMA Floodplain map for the coastal area was updated in June of 2020. These flood plain changes can result in substations that were not within the flood plain at construction being "reclassified" such that the original design, which was appropriate at the time, is no longer sufficient. The model established for Substation Flood Mitigation evaluates substations in the flood plain with the potential based on historical data to have at least four (4) feet of flood mitigation, and then DEF resources perform further analytics to ensure the prudency and most cost-effective measure for mitigation.

Q. What is your response to the comment that DEF has not suffered outage time due to flooding of DEF's substations?

A. Witness Mara shared his understanding that DEF has not had any outages due to flooding of its substations in recent years, stating, "there was one instance where sandbags were deployed at a control house but there were no outages." Witness Mara seems to indicate that a 3-year flood history is indicative of a 100-year flood, but substations are built to remain functioning over a prolonged period, so a 3-year window is not sufficient to prudently plan for the long-term functionality and service of the substation (as discussed above, the NESC code is updated regularly while the FEMA flood plain is updated as necessary, both of which can result in changed requirements at specific locations).

I recommend retaining the Substation Flood Mitigation Program in its entirety.

Q. Mr. Mara recommends eliminating the Loop Radially Fed Substation Program from the plan in favor of prioritizing hardening transmission lines through replacing wood structures with non-wooden structures. Do you agree with this approach?

A. No, I do not agree for a couple of reasons. For one thing, accepting what he said regarding the lower rate of failure for hardened structures as true, it does not mean that hardened structures will be able to withstand each and every extreme weather event that may eventually occur. Hence, the looping of radially fed substations (as discussed below) will further harden the system against the impacts of extreme weather events in a cost-effective manner.

The looping of radially fed substations is targeted at specific existing "single point of failure" vulnerabilities. For example, a short 69kV radial tap serves a substation that cannot be isolated and restored through switching if a line fault occurs on that tap. A typical design allows for a slight adjustment to the line route to "loop through" the substation so there is no portion of the transmission line that would prevent restoring power to the substation. Looping through the substation in this manner allows the transmission line to be "sectionalized" by operating switches to isolate a faulted section of the line and to restore the electric supply to the substation in the event of a line outage. Switches installed within the substation can also be equipped with remote monitoring and control more easily than switches located on the transmission line at a distance from the substation.

The ability to isolate events or damage due to extreme weather events allows for reduction of outage times. Restoration costs are reduced because of the ability to quickly restore customers out of service and have a more planned approach to any repairs required versus dedicating resources to first identify and then repair damage in an emergency response.

Q. Mr. Mara recommends eliminating the Substation Hardening Program from the plan indicating that the BCA is only 1%. Do you agree?

A. No, I do not agree. I referred to Exhibit KML-2 and it was unclear how the 1% BCA he refers to was calculated. The 1% BCA does not match Table 1 located in Witness Lloyd's Testimony. Table 1 clearly shows all of DEF's programs have a benefits-to-cost ratio greater than 1, which is inclusive of the Substation Hardening program. As a result, I recommend that this program be included in the SPP.

Q. Describe why the Transmission Substation Hardening Program meets the requirements of Rule 25-6.030, F.A.C.

A. The Transmission Substation Hardening program is intended to upgrade targeted equipment that is generally more vulnerable during extreme weather events to protect the integrity of the grid. Simply put, relays and breakers are needed as a combination to protect the Transmission and Distribution systems to ensure reliable service for our customers. Witness Mara opines that "outages will still occur and therefore the cost to restore will not be reduced." Rather than provide a basis for eliminating the program, this opinion supports the need for the Substation Hardening program. As faults occur on the system, the breakers and relays are relied upon to operate and safely isolate the faulted segment, which reduces outages and outage durations to customers connected to facilities that are not damaged. During extreme weather events, breakers and relays are called upon to operate more frequently and failure to operate, when necessary, would result in longer outage durations for our customers. We also expect that the ability to isolate the faulted segment will also decrease restoration costs by saving time identifying areas of need, thereby allowing DEF's restoration crews to focus efforts appropriately.

Q. Do you agree with Witness Mara that there are no significant performance changes with using modern breakers?

A. No. During extreme weather events, breakers and relays will operate multiple times as the weather affects the transmission and distribution systems. Oil breakers have a limited number of operations especially in circumstances where they are operating numerous times over a short period, such as during extreme weather events. When oil circuit breakers are repeatedly called to operate, they can generate arcing gasses within the oil tank that can accumulate and result in catastrophic failure. Replacement of the breakers with gas or vacuum breakers, upgrades to a faster response time and they can withstand a higher number of operations. Failure to operate fast enough to clear fault currents will activate backup protection systems, potentially leading to a larger outage for our customers.

Q. Do you agree with Witness Mara that def has no choice but to replace electromechanical relays with digital?

A. Not necessarily; DEF does have a choice regarding the timing of the upgrade from electromechanical to digital relays. Electromechanical relays still perform the designed function, and DEF has an available inventory of electromechanical relays it can use, however, they do not offer the additional benefits that I describe below. DEF has implemented electromechanical for electromechanical relay replacements to extend the life of the facility and maintain reliability for our customers. DEF agrees the upgrade of non-communicating electromechanical relays to digital relays provides enhanced monitoring and communication capability and eventually all relays on the system will be upgraded to digital, but to perform that upgrade at this time would be cost prohibitive.

Protection systems (i.e., grouping of relays) are designed to detect and isolate faults or disturbances on the transmission or distribution systems. During extreme weather events, relays are needed to quickly identify the fault thereby limiting the severity and spread of system disturbances and preventing possible damage to equipment. Additionally, some digital relays enable the use of device data to calculate the distance of a line fault allowing for faster identification and restoration. Substation Hardening reduces restoration cost and outage time through the reduced resource time needed to manually patrol the length of the transmission line or facility prior to restoring customers or the BES transmission system.

Q. On June 27, 2022, OPC filed a Motion to Accept Amended Testimony along with amendments to both witnesses' pre-filed direct testimonies. Have you reviewed the amended testimonies, and if so, what impacts do the amendments have on your rebuttal testimony?

A. Yes, I have reviewed the proposed amended testimonies, as well as Mr. Lloyd's response contained in his rebuttal testimony. I fully agree with Mr. Lloyd and also believe that, because OPC's witnesses' testimonies continue to include their faulty reasoning and conclusions, as I have discussed in the foregoing testimony, it is important to present the Company's response as it pertains to the Transmission specific portions of the Plan.

III. CONCLUSION

Q. Mrs. Howe, your rebuttal covers a lot of ground, but did you respond to every contention regarding the Company's proposed plan in your rebuttal?

A. No. Intervenor testimony on the SPP involved many pages of testimony and I could not reasonably respond to every single statement or assertion and, therefore, I focused on the issues that I thought were most important in my rebuttal testimony. As a result, my silence on any particular assertion in the intervenor testimony should not be read as agreement with or consent to that assertion.

Q. Does this conclude your testimony?

A. Yes.