BEFORE THE STATE OF MAINE PUBLIC UTILITIES COMMISSION

In the Matter of Commission Initiated
Investigation into Rate-Setting Mechanisms
Regarding Non-Wire Alternatives
Docket No. 2018-00171

Direct Testimony of
Melissa Whited

On Behalf of
Maine Office of the Public Advocate

With Regard to
Utility Incentives for Non-Wires Alternatives

December 17, 2018

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I. INTRODUCTION AND OVERVIEW

INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title, and employer.

A. My name is Melissa Whited. I am a Principal Associate at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity and gas industry regulation, planning and analysis. Our work covers a range of issues including integrated resource planning; economic and technical assessments of energy resources; electricity market modeling and assessment; energy efficiency policies and programs; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients including attorneys general; consumer advocates; public utility commissions; environmental groups; federal agencies including the Environmental Protection Agency, Department of Energy, Department of Justice, and Federal Trade Commission; and the National Association of Regulatory Utility Commissioners. Synapse has over 20 professional staff with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. I have worked on a variety of electricity regulatory and ratemaking issues for more than seven years. At Synapse, I work extensively on issues related to utility regulatory models, rate design, policies to address distributed energy resources (DERs), and market power. For example, I am currently providing consulting services regarding the incorporation of distributed energy resources in utility planning processes in New York's "Reforming the Energy Vision" proceeding.

I have presented on performance-based regulation, utility incentives, and rate design to the National Association of Regulatory Utility Commissioners (NARUC), the National Association of State Utility Consumer Advocates (NASUCA), the Western Interstate

Energy Board, the Midwest Governors Association, the National Governor's Association Learning Lab on New Utility Business Models, and the University of Wisconsin.

In 2015, I was the lead author of the report *Utility Performance Incentive Mechanisms: A Handbook for Regulators*. I have testified on issues related to utility regulation and ratemaking before public utility commissions in California, Rhode Island, New York, Utah, Hawaii, Texas, Massachusetts, Virginia, and the Federal Energy Regulatory Commission.

I hold a Master of Arts in Agricultural and Applied Economics and a Master of Science in Environment and Resources, both from the University of Wisconsin-Madison. I have a Bachelor of Arts from Southwestern University in Georgetown, Texas. Prior to rejoining Synapse, I published in the *Journal of Regional Analysis and Policy* regarding the economic impacts of water transfers in Texas, analyzed state water efficiency policies while at the Wisconsin Public Service Commission, and conducted econometric analyses of energy efficiency cost-effectiveness.

The foregoing and additional background are detailed in my resume, attached hereto as Exhibit MW-1.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Maine Office of the Public Advocate (OPA).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the utility incentives for non-wires alternatives proposed by Central Maine Power Company ("CMP") and Emera Maine ("Emera"), collectively "the Utilities."

SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your primary conclusions.

A. My primary conclusions include the following:

- The Utilities' proposed NWA incentive mechanism is insufficient to make the Utilities financially indifferent to investments in traditional infrastructure in virtually every case that I analyzed.

- The Utilities' proposal does not address the Utilities' incentive to prefer investments in capital infrastructure over expenses, even when an expensed option would provide significantly more ratepayer savings.
- The Utilities' proposal generally provides greater earnings for the utility as the cost of the NWA increases. Thus, the proposal also encourages the Utilities to implement relatively high-cost utility-owned NWAs, when NWAs are incentivized at all.
- An alternative shared savings mechanism together with capitalized expenses would put NWAs on a more equal footing with traditional T&D investments and would help address the Utilities' bias toward capital investments.
- The Utilities' NWA identification and implementation process is deficient, because it:
    - is based on a reactive planning process with little transparency,
    - would not require the Utilities to seek lower-cost third-party NWA solutions, and
    - does not contain critical information (such as full benefit-cost analysis results or measurement and verification metrics).
- The Utilities' proposal to implement revenue decoupling for Emera should only be adopted if additional customer protection measures are implemented.

Q. Please summarize your recommendations regarding utility NWA incentives and cost recovery.

A. I offer five recommendations regarding utility NWA incentives and cost recovery mechanisms. Specifically, I recommend the Commission:

- Reject the Utilities' proposed NWA incentive mechanism and cost recovery mechanism.
- Direct the Utilities to file a complete financial model that shows the utility earnings and ratepayer savings under various shared savings mechanisms.
- Approve a shared savings mechanism with approximately 30% savings retained by the Utilities, as well as approve the capitalization of NWA expenses.

- Allow the utility to recover NWA incentives only once certain capacity benchmarks are achieved, with the final incentive payments made only following the utility's next rate case.

- Allow recovery of capitalized NWA assets only beginning at the time of the utility's next rate case, but allow NWA expenses to be recovered on a current basis.

Q. Please summarize your recommendations regarding the NWA planning and implementation process.

Regarding NWA identification and implementation process, I recommend that:

- The cost threshold for distribution NWAs be adjusted downward to $500,000 so that less expensive projects are still considered for non-wires alternative solutions.

- The Utilities be required to conduct an annual distribution system study to evaluate needs over the following five years.

- The Utilities be required to issue an RFP for each NWA opportunity, and use an independent observer to oversee the NWA evaluation and selection process.

- The Utilities' make publicly available their Annual NWA Deployment Plans, and that the OPA and interested stakeholders have full participation rights in the review of the ADP, including the ability to raise questions and concerns.

- The Utilities' proposal regarding a Commission finding of prudency be rejected, because the Commission should never be precluded from conducting a future prudency review.

- The ADP contain the results and electronic workpapers of a benefit-cost analysis for each new NWA project, for each NWA that was not selected, and updated benefit-cost analysis results for ongoing NWAs.

- The ADP include additional details regarding the estimated costs for selected NWAs and the traditional project to be displaced, as well as measurement and verification procedures.

- The Utilities submit quarterly reports for each ongoing NWA project detailing the expenditures and program activities undertaken, including all relevant details with respect to project costs, project in-service dates, incremental costs incurred, operational savings, and other benefits.

Q. What do you recommend regarding Emera's RDM proposal?

A. I recommend that the revenue decoupling mechanism should be adopted at the time of Emera's next rate case, rather than before. This will ensure that the allowed revenues contained in the RDM are appropriately based on the Company's most recent verified revenue requirements. Further, this will allow the Company's allowed ROE to be adjusted to reflect the reduced risk associated with the RDM.

ORGANIZATION OF TESTIMONY

Q. How is the remainder of your testimony organized?

A. My testimony is organized in five sections:

Section II: This section addresses the problems with the utilities' proposed NWA incentive mechanism and proposes an alternative NWA incentive.

Section III: This section addresses cost recovery and incentive payment concerns and recommendations.

Section IV: In this section, I describe issues associated with the Utilities' proposed NWA identification and implementation process and recommend changes to the process.

Section V: This section addresses Emera's request for decoupling.

Section VI: I summarize my primary conclusions and recommendations in this section.

II. PROPOSED UTILITY INCENTIVES FOR NWAs

RATIONALE FOR NWA INCENTIVES

Q. Why are the Utilities proposing incentives for non-wires alternatives?

A. Maine's Smart Grid Policy Act (35-A M.R.S. § 3143) was implemented "in order to ensure that all ratepayers and the State as a whole are afforded the benefits of smart grid functions and associated infrastructure, technology and applications." A key means for accomplishing this is by utilizing distributed energy resources as cost-effective alternatives to transmission and distribution projects that would otherwise be developed by utilities to meet system reliability needs – i.e., through "non-wires alternatives."

However, it is widely recognized that the current regulatory model does not provide incentives for the development of non-wires alternatives, and in fact provides utilities with financial disincentives for procuring lower-cost or non-capital solutions. This is because of two reasons:

1) Regulated utilities earn a return on capital investments. When a utility's rate of return is greater than the cost of borrowing, utilities have a financial incentive to maximize their capital expenditures in order to increase rate base and thereby increase profits. This is often referred to as the Averch-Johnson effect.[1]

2) Reduced sales result in revenue reductions. To the extent that NWAs such as energy efficiency or distributed generation reduce sales, utility revenues will be reduced unless sales and revenues are decoupled.

In recognition of utility disincentives, the Act specifically provided for the Commission to adopt rules regarding "methods to address financial disincentives for transmission and distribution utilities to promote smart grid function."[2] Accordingly, in 2016, the Maine

[1] As Commissioner Williamson noted in his Concurring Opinion in Docket 2016-00049 on February 6, 2018, regulatory lag can mitigate a utility's incentive to invest in higher-cost options. However, as I demonstrate below, regulatory lag is unlikely to encourage a utility to invest in a non-capitalized solution (such as an NWA provided by third parties). Further, a utility is likely to file for a rate case or request special cost recovery treatment for large, unusual capital costs (such as a large new transmission line). In these cases, regulatory lag would not play a major role in encouraging the utility to seek the least-cost solution.

[2] 35-A M.R.S. § 3143(3).

Public Utilities Commission (Commission) opened Docket No. 2016-00049, an Investigation into the Designation of a Non-Transmission Alternative (NTA) Coordinator, to address the statute's directives regarding non-wires alternatives.

Q. What did the Commission order in Docket 2016-00049 regarding utility disincentives to NWAs?

In its Order on December 15, 2017, the Commission found that the Utilities should "undertake consideration of non-wires alternatives as part of their planning function," and that the incentive problem should be addressed directly through incentive rate proposals. The Commission directed the Utilities to file "rate proposals that address incentives by putting wires and non-wires solutions on an equal footing from a rate-making incentive perspective."[3] To comply with the Commission's Order, CMP and Emera Maine, on June 22, 2018, filed a report prepared by Concentric Energy Advisors, referred to as the "Initial Concentric Report." On October 1, 2018, the Utilities filed a supplemental report with more details regarding their proposals (the "Concentric Report").

THE UTILITIES' NWA PROPOSAL FAILS TO ADEQUATELY ADDRESS UTILITY DISINCENTIVES TO NWAS.

Q. What did the Utilities propose in terms of NWA incentives?

A. To counter the incentive to invest in traditional "wires" solutions, the Utilities propose the Commission do the following:

1) Provide an incentive in the form of a positive earnings opportunity. Specifically, the Utilities propose a separate incentive ranging from 50 to 150 basis points (applied to the NWA cost), depending on the magnitude of the savings that the NWA represents relative to a traditional investment.[4]

2) Treat NWA expenditures in a manner similar to traditional T&D investments by including capital costs related to NWAs in rate base, collecting investment costs

[3] Maine Public Utilities Commission, Order, Docket 2016-00049, December 15, 2017, p. 16

[4] This adder would scale with the magnitude of savings. On the low-end, the utilities would earn the 50-basis-point adder if 1 percent of the initial NWA investment represents 50 percent or more of the expected annual NWA savings; on the high-end, CMP and Emera would earn the maximum 150-basis point adder if 1 percent of the initial NWA investment represents 20 percent or less of total NWA savings. Concentric Report, pp. 9-10

through depreciation over an appropriate time period, and applying the rate of return to the net investment balance in rate base. In situations where the utility incurs expenses for NWAs (such as through payment to third parties for NWA services), the Utilities request that these costs be "recovered in rates on a current basis."[5]

3) Approve a revenue decoupling mechanism for Emera.

I address the first proposal in this section, the second proposal in Section II, and the decoupling proposal in Section V.

Q. Why do the Utilities propose an additional incentive beyond treating the NWA expenditures in a manner similar to traditional T&D investments?

A. An NWA would only be selected if it is lower cost than the traditional wires investment. Although this would provide savings to ratepayers, it would necessarily result in a lower earnings opportunity for the utility, unless some of the savings are retained by the utility through regulatory lag. The Utilities suggest that the basis points adder would correct for the lesser earnings opportunities represented by non-wires alternatives and would induce them to give good faith consideration to NWAs in the planning process.[6]

Q. Please explain how "regulatory lag" impacts the Utilities' incentives.

A. Regulatory lag refers to the time period between cost incurrence and revenue adjustments. Under traditional cost of service regulation, a utility's revenue requirement is only adjusted in a rate case. If costs increase between rate cases but revenues do not, then a utility's profits are reduced. This provides an incentive for the utility to minimize expenditures between rate cases. Therefore, if a utility must make an investment to maintain reliability, then the utility may choose a lower-cost investment if it will not be able to begin to recover those costs immediately. For example, if we assume that rate cases occur every four years, then the average "lag" on recovery of an investment would be approximately two years. If the utility makes a lower-cost NWA investment as opposed to a higher-cost capital investment, then it "saves" the difference between the investments for the lag period (e.g., two years).

[5] Concentric Report, p. 8
[6] Concentric Report, p. 10

Q. How should regulatory lag factor into the setting of an incentive?

A. Regulatory lag can provide a strong cost control incentive.[7] However, regulatory lag is not a panacea for a utility's incentive to increase its rate base for several reasons:

- The incentive power of regulatory lag diminishes as the time remaining before the next rate case decreases. The strongest regulatory lag incentive occurs in the period immediately following the year upon which rates were set, and then diminishes as the next rate case approaches. Therefore, the incentive is uneven and significantly reduced for investments that occur close to the utility's next rate case.

- The utility may be able to shift the timing of some investments so as to reduce regulatory lag.

- The utility always has the ability to initiate a new rate case should the gap between revenues and costs become too large. Thus, for large investments, the utility may decide to initiate a new rate case rather than absorb the impacts of regulatory lag.

- Efficiency savings due to regulatory lag are unlikely to equal the earnings from a capitalized solution, and therefore regulatory lag does not fully address the utility's capital bias in cases where an expensed solution would be less expensive.

Q. Please clarify what you mean by a "capitalized solution" and an "expensed solution" in the context of NWAs.

A. By a "capitalized solution," I mean a utility investment in a physical asset (such as a battery) that would be depreciated over time and earn a return.

By an "expensed solution," I mean a situation in which the utility incurs expenses, such as for demand-response programs or payments to third parties for specific NWA services.

[7] Alfred Kahn (1971), The Economics of Regulation, Vol. 2, p. 48.

Q. Do the proposals put forward by the Utilities put wires and non-wires solutions on an equal footing from an incentive perspective?

A. No. The Utilities' proposal does not meaningfully address the incentives problem. The utilities' proposal fails to put NWAs on an equal footing with traditional T&D solutions in several ways:

- First, the incentive is insufficient to make the Utilities financially indifferent to investments in traditional infrastructure in virtually every case that I analyzed, unless one assumes regulatory lag.
- Second, the proposal does not address the Utilities' incentive to prefer investments in capital infrastructure over expenses, even when an expensed option would provide significantly more ratepayer savings.
- A third problem with the Utilities' proposal is that the higher the cost of the NWA, the greater the earnings for the utility over most of the applicable incentive range. Thus, the proposal also encourages the utilities to implement relatively high-cost utility-owned NWAs, when NWAs are incentivized at all.

The Utilities' proposal suggests that they have little interest in pursuing NWAs, particularly if NWAs occur as expenses, such as through a third-party contract. Instead, the Utilities' proposal perpetuates the bias towards utility-owned traditional capital investments, and utility investments in general.

Q. Have the Utilities developed a detailed financial model for comparing NWAs and traditional wires investments, or for comparing any incentive they would earn under their proposal to the return earned on a traditional wires solution?

A. It is unclear whether the Utilities have developed a detailed financial model for comparing NWAs and traditional investments, or for assessing the incentive they would receive under an NWA. A financial model applied to a hypothetical NWA was requested by the OPA in discovery (OPA-001-006), but the Utilities responded that the example would require "significant time and resources" to develop. Instead, the Utilities provided a simplified analysis in the file "OPA-001-006_Attachment_1_(2018-171).xlsx."

Q. Was the simplified model provided by the Utilities sufficient to evaluate their proposal?

A. No. The Utilities' simplified analysis omitted key factors (such as the cost of debt, the allowed return on equity, taxes, overhead loaders, etc.). Moreover, the calculations were not accurate, as the revenue requirement calculation in the workbook did not factor in depreciation expense for the wires solution.

Q. How did you reach the conclusion that the Utilities' proposal fails to put NWAs on an equal footing with traditional investments?

A. I constructed a spreadsheet model to analyze the return on equity and any financial incentive that a utility would earn through an NWA solution relative to a traditional T&D investment. I first modeled a traditional investment with an up-front capital cost of $10 million depreciated over 20 years with a small amount of annual expenses.[8] I assumed a 9% return on equity (ROE), a 5% interest rate on debt, and a weighted average cost of capital of 7%.

I then modeled two types of NWAs: an NWA as a capital investment, and an NWA as an expenses-only investment. The expenses-only NWA was modeled at 70% of the cost of the capitalized NWA in order to evaluate whether the Utilities' proposal would provide substantially larger incentives for substantially larger ratepayer savings, even if the NWA was not put into rate base.

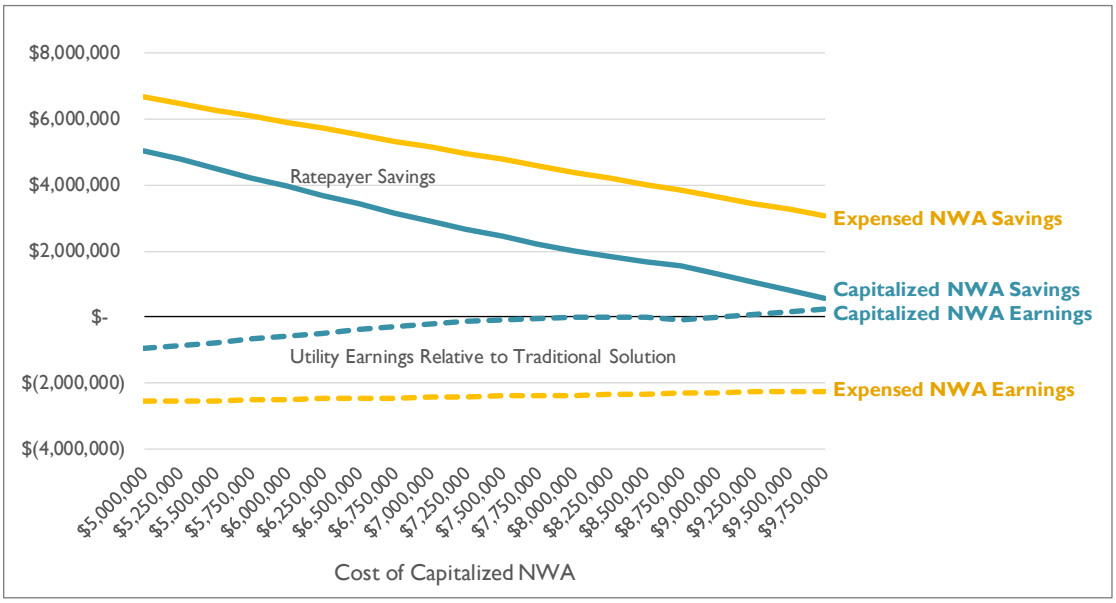
Finally, I compared the earnings on the NWAs to that of a traditional wires investment, as well as the ratepayer savings associated with the NWAs. Total utility earnings were estimated as the net present value of any return on equity of a capital investment, plus any incentive payment earned. Ratepayer savings were estimated as the net present value difference between the traditional solution and the NWA (including any incentive earned on the NWA).

[8] Annual expenses were set at $50,000 per year to represent miscellaneous expenses. This is a hypothetical example, rather than indicative of any actual NWA.

Q. Please describe the results of your financial model.

A. The financial model results are presented in Figure 1 below. The two solid lines on top represent potential ratepayer savings from NWAs, while the bottom dashed lines show utility earnings relative to the traditional solution. Where the dashed lines are below zero, utility earnings are less than the earnings on a traditional T&D investment. These results are shown across a wide range of NWA costs, ranging from $4 million to nearly $10 million.

Figure 1. NWA Costs, Ratepayer Savings, and Utility Earnings under Utility Proposal



The model shows that, under the Utilities' proposal, ratepayer savings (the solid lines) decline as the cost of the NWA increases and approaches the cost of the traditional solution. At the same time, the utility earnings generally increase as the cost of the NWA increases, particularly for the capitalized solution. This is because the utility earns a higher return on higher-cost investments.

Q. What do you conclude from your modeling?

There are several key take-aways from this modeling exercise:

- In nearly every case, the earnings provided by an NWA would be less than that earned on a traditional T&D investment, assuming an ROE on traditional investments of 9% or higher.[9]
    - In particular, under the capitalized NWA solution, the utility earnings are less than for traditional T&D investments unless the cost of the NWA is almost as much as the cost of the traditional T&D solution. This means that unless the cost of the NWA is very similar to that of the T&D solution, the NWA incentive is not large enough to offset the foregone return on the higher-cost, traditional investment.
    - Under the non-capitalized (expensed) NWA solutions, the utility earnings are always less than those for traditional T&D investments and those under the capitalized NWA. This is primarily because the utility earns no return on expensed solutions.
- Non-capitalized (expensed) NWA solutions are at a significant disadvantage relative to capitalized NWAs, even though the non-capitalized NWA could potentially provide much greater savings to ratepayers. Although a portion of the incentive is based on the savings provided by the NWA, this proportion is inadequate to counter the potential earnings from more costly capital investments.
- The Utilities' proposed incentive is generally inversely proportional to ratepayer savings: it would provide greater earnings to the utility in return for lower ratepayer savings.

[9] Under an ROE of 9%, the NWA only produces greater earnings than the traditional wires solution when the present value (PV) of the NWA cost is at least 87% of the PV of the traditional solution. Lower ROE rates provide a slightly larger range over which NWA earnings are at least as much as traditional solution earnings, but in the majority of cases the NWA remains less profitable for the utility.

Q. What do these model results imply for ratepayers?

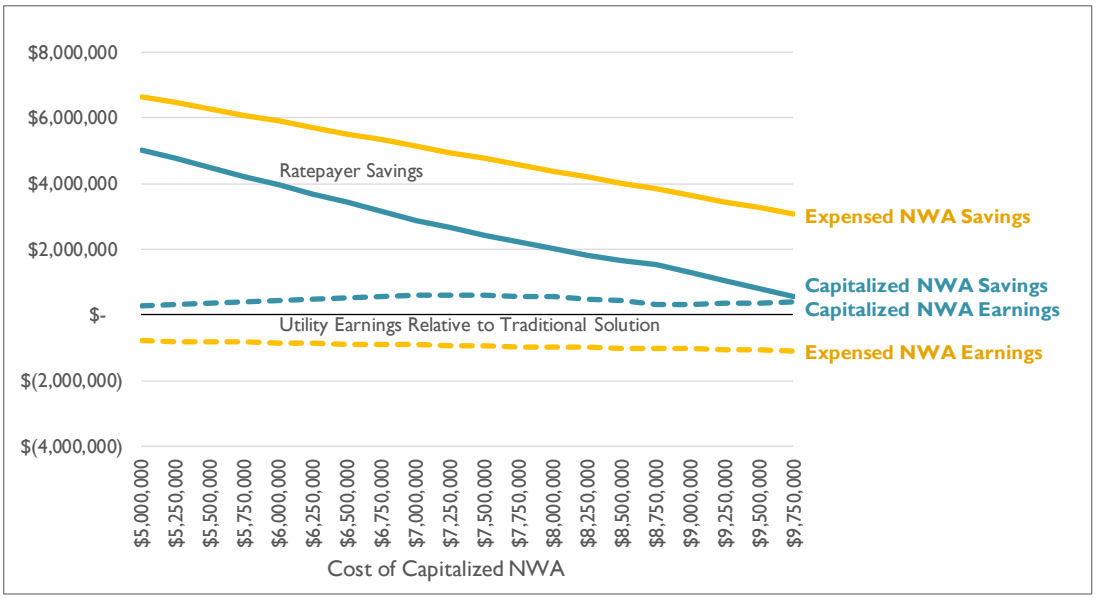
A. The results show that millions of dollars of potential ratepayer savings may not be realized, because the Utilities are likely to continue to favor traditional solutions over NWAs under their proposed incentive.

Q. Did you account for regulatory lag?

A. Yes, I modeled a separate scenario that included the impacts of regulatory lag. If a utility must make an investment to maintain reliability, then the utility may choose a lower-cost investment if it will not be able to begin to recover those costs immediately.

The "lag savings" from choosing a lower-cost resource increase the utility's overall earnings. This is shown in the figure below.

Figure 2. NWA Costs, Ratepayer Savings, and Utility Earnings under Utility Proposal with Regulatory Lag



Q. What do the results of your model show when assuming two years of regulatory lag savings?

A. If the utilities retain two years of efficiency savings from implementing a lower-cost NWA, then the utility would earn a higher return by investing in the lower-cost solution.

Q. Do efficiency savings due to regulatory lag ensure that the Utilities will invest in lower-cost NWAs?

A. No, for several reasons. First, as noted above, the efficiency incentive provided by regulatory lag declines as a rate case approaches. Thus, only when a rate case is two or

more years away would the regulatory lag savings likely be strong enough to overcome the incentive to invest in higher-cost traditional T&D solutions.

In addition, the regulatory lag incentive is diminished to the extent that investments can be postponed in order to reduce lag. If there is any flexibility in the timing of a traditional T&D investment, the utility may choose to postpone the investment until shortly before the next rate case. An NWA incentive does not overcome this.

If a utility cannot shift the timing of an investment and the size of the traditional investment is large enough, the utility may simply initiate a rate case to avoid regulatory lag.

Q. Does regulatory lag encourage the Utilities to choose the least-cost solution?

A. No. As evidenced by the figure above, even factoring in two years of regulatory lag "savings" does not offset the incentive the Utilities would gain with a capitalized NWA over a lower-cost expensed NWA. Thus regulatory lag is generally not sufficient to overcome capital bias.

Q. Please comment on the ability of the Commission to declare higher-cost investments imprudent. Would this provide a sufficient counterweight to the Utilities' incentive to invest in higher-cost capital solutions?

A. In theory, prudency reviews can mitigate some of the incentive to maximize capital expenditures. However, in practice prudency reviews and disallowances are rare, burdensome, and are mostly applied to large capital expenditures. It can be difficult to obtain evidence that an alternative solution existed at a lower cost for a specific investment. This is particularly true if the utility does not issue an RFP for alternative solutions, or if it fails to identify a potential need sufficiently in advance to enable an NWA to be developed. In short, there exist many ways that the utilities can obfuscate the viability of alternatives to a traditional T&D investment. As long as the incentive falls short, the utilities may be motivated to do so.

Q. What do you recommend regarding the Utilities' proposed NWA incentive mechanism?

A. I recommend that the Commission reject the Utilities' proposed NWA incentive mechanism because it is flawed and does not attain the aims articulated in the Smart Grid

Policy Act and in the Commission's order in Docket No. 2016-00049 of mitigating utility disincentives to NWAs.

PROPOSED ALTERNATIVE MECHANISM

Q. What should be done to address the Utilities' disincentive to pursue NWAs?

A. A core purpose of the Smart Grid Policy Act is to provide net benefits to ratepayers through the development of NWAs that are less costly than wires solutions. To accomplish this goal, we must overcome the disincentives inherent in the current regulatory framework. This can be done in one of several ways:

1) Appointing a third party to develop least-cost solutions to needs on the transmission and distribution grid. This option was rejected by the Commission in 2016-00049;

2) Significantly increasing transparency and oversight of utilities' T&D planning practices and solution procurement to ensure that no preferential treatment is given to utility-owned solutions; or

3) Providing an equal or greater earnings opportunity on NWAs relative to traditional utility investments.

Each of these options has benefits and drawbacks. The first two options do not require providing utilities with earnings on NWAs, and therefore could potentially provide greater savings to ratepayers. However, the first two options also have higher administrative burdens and would likely not address the issue of information asymmetry between regulators and the Utilities (who have the most in-depth knowledge of their systems).

The third option is what the Commission intended to accomplish when it ordered the Utilities to file "rate proposals that address incentives by putting wires and non-wires solutions on an equal footing from a rate-making incentive perspective." However, this option will only work if the proposal provides a meaningful counterweight to the financial earnings associated with traditional capital solutions.

Q. What do you recommend as an alternative to the Utilities' proposed incentive mechanism?

A. If the Commission wishes to adopt a rate proposal that puts wires and non-wires solutions on an equal footing, then it should adopt an incentive mechanism that ensures the Utilities will (1) proactively identify all NWA opportunities, (2) will seek the least-cost NWA solution, regardless of whether it is a capital investment, and (3) will be rewarded for maximizing ratepayer savings.

This can be accomplished by adopting a shared savings mechanism based on net benefits to ratepayers that (a) provides the Utilities with approximately the same level of earnings as a traditional solution, (b) treats expenses and capital investments equally from an earnings perspective, and (c) provides greater utility earnings in exchange for greater ratepayer savings.

Q. Please explain your proposal in greater detail.

A. I propose that the incentive be structured as a pure shared-savings mechanism with approximately 30% of the net present value of ratepayer savings being retained by the utility. In addition, I propose that the net present value of expensed NWAs be capitalized to allow the Utilities to earn a return on these NWA expenditures in order to offset much of the disincentive associated with non-capitalized NWA solutions.[10]

Q. Why do you propose to allow the Utilities to earn a return on non-capitalized NWA solutions?

A. The purpose of developing an NWA is to provide customers with savings relative to a traditional solution that will be capitalized and recovered from ratepayers—with a return —over decades. The Utilities should have an incentive to procure lower-cost non-capitalized solutions where this would be cost-effective. This means that the utility should earn the same amount on a non-capitalized solution as a capital asset, as long as it also provides ratepayer savings.[11]

[10] This would be on top of the shared savings mechanism and is necessary to counter the Utilities' capital bias.

[11] In the case of non-transmission alternatives, the comparison should be between the cost of the traditional solution that will be borne by Maine ratepayers (e.g., 8% of the total cost when the investment costs are socialized per the ISO-New England tariff) and the cost of the NWA.

For example, a utility should not construct a new battery storage system when the need could be solved more cost-effectively using demand response provided by a third-party vendor. Ratepayers will benefit the most if the Utilities procure the least-cost solution.

Q. Have other jurisdictions allowed the utility to earn a return on expenses?

A. Yes. For example, the New York Public Service Commission determined that allowing Consolidated Edison to earn a return on its targeted demand management program costs is reasonable, as such an incentive mechanism "is designed to make Con Edison financially indifferent between traditional capital and non-traditional customer-side solutions."[12]

Q. How does your proposal compare to the Utilities' proposal in terms of the magnitude of utility earnings and ratepayer savings?

A. On an individual project-by-project basis, my proposal would provide somewhat greater earnings to the utilities, resulting in lower ratepayer savings. However, taken on the whole, I expect that my proposal would produce greater ratepayer savings because the incentive will encourage the utilities to identify many more potential NWA opportunities than they would otherwise. Without a meaningful incentive, I am concerned that the Utilities will fail to identify many potential NWA opportunities, particularly if they believe that the least-cost solution may be a third-party expensed NWA.

In order to provide the maximum savings to ratepayers, the Utilities must shift from their current reactive approach to distribution planning and instead adopt a proactive approach in which they (a) identify potential NWA opportunities well in advance, and (b) actively engage with third-party providers to find the least-cost NWA solutions. I believe that the utilities will only wholeheartedly pursue NWAs if they have a meaningful financial incentive to do so.

Q. Please describe the shared savings approach that you recommend.

A. I recommend that a simpler shared savings approach be adopted, where the Utilities would simply retain a portion of the difference between the present value of the

[12] New York Public Service Commission, TDM Program Order, Case 15-E-0229, p. 13

traditional solution and the NWA. For example, the utility could be allowed to retain 30% of the savings relative to the traditional solution. The magnitude of the utility share should be sufficient to motivate the utility to select least-cost solutions, but low enough to allow ratepayers to retain the majority of the savings.

Q. What are the advantages of a pure shared savings mechanism over the Utilities' proposal?

A. This approach has several advantages:

- If the retained percentage is large enough, it delivers greater rewards to the Utilities in return for greater ratepayer savings. In contrast, the shared savings component of the Utilities' proposal is too small to incentivize the Utilities to pursue the least-cost solution.
- It is simpler, and thus more transparent, than the Utilities' proposal.
- There are many precedents for shared savings incentive mechanisms. They are commonly found in energy efficiency programs, and they are currently in use in New York for NWAs.

Q. Do any other jurisdictions use a shared savings mechanism for NWAs?

A. Yes. Many of the utilities in New York use a shared savings mechanism based on a 30% retention of "initial net benefits," with a cap of 50% of the initial net benefits.[13] In fact, the New York Public Service Commission rejected Con Edison's proposal for a basis point adder of up to 150 bps in favor of a pure shared savings mechanism. In doing so, the New York Commission wrote that proposed ROE adder "could have the unintended effect of encouraging the Company to increase spending, since as proposed the ROE incentive mechanism is to be applied to the Company's unrecovered costs. For example,

[13] *See, for example:* New York Public Service Commission, Order Implementing with Modification the Proposal tor Cost Recovery and Incentive Mechanism for Non-Wire Alternative Project, Case 14-E-0318, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service., July 15, 2016; and New York Public Service Commission, Order Approving Shareholder Incentives, Case 15-E-0229, Petition of Consolidated Edison Company of New York, Inc. for Implementation of Projects and Programs That Support Reforming the Energy Vision, January 25, 2017. This incentive was set at 30% of the Initial Net Benefits, with a Final Incentive Cap of 50% of the Initial Net Benefits.

Con Edison could earn a larger incentive, in terms of dollars, for investing its entire $60 million budget regardless of if it could achieve the same results for only $50 million."

Q. Have you modeled your proposal?

A. Yes. I modeled a hypothetical case in which a traditional utility T&D investment is compared to an NWA owned and operated by the utility ("NWA - Capitalized"), and an NWA procured from a third party ("NWA – Expensed"). These solutions are shown in the table below as different columns.

- The first row shows the net present value of the revenue requirement for each solution. I assumed that the expensed NWA would cost 70% of the cost of the capitalized NWA. The next row shows the earnings the utility would receive on any capitalized solution (including the case in which the expensed solution is capitalized, as under my proposal.)
- The third row shows the incentive the utility would earn based on the Utilities' proposal, while the fourth row shows the earnings from the 30% shared savings mechanism.
- Row 7 compares the total utility earnings to the traditional solution.
- Row 8 shows total ratepayer savings for each solution.

Table 1. Comparison of NWAs and Incentives

			A.	B.	C.	D.	E.	F.
				NWA - Capitalized		NWA - Expensed		
			Trad'l T&D ($1000s)	*Utility Proposal ($1000s)*	*Shared Savings ($1000s)*	*Utility Proposal ($1000s)*	*Shared Savings ($1000s)*	*Shared Savings - Capitalized ($1000s)*
1	Costs	NPV of Revenue Requirement	10,400	6,900	6,900	4,800	4,800	6,200
2	Earnings	Utility Equity Earnings before Incentive	2,900	2,000	2,000	0	0	1,400
3	Incentive	Utilities' Proposed Incentive	--	700	--	500	--	--
4		30% Shared Savings	--	--	1,100	--	1,700	1,300
5		Total Utility Earnings	2,900	2,700	3,100	500	1,700	2,700
6		**Total Utility Earnings Relative to Traditional Solution**		(200)	**200**	(2,400)	(1,200)	(200)
7		**Total Ratepayer Savings**		2,800	2,400	**5,100**	3,900	2,900

Q. Which columns represent the Utilities' proposal, and which columns represent your proposal?

A. Columns B and D show the Utilities' proposal. Columns C and F represent my proposal. In addition, I have included Column E, which shows a shared savings mechanism applied to non-capitalized NWA expenses. This proposal does not address the Utilities' capital bias, which is why I do not recommend it.

Q. What does your analysis reveal?

A. First, the example shows that the Utilities would have no incentive to pursue the two solutions with the greatest ratepayer savings (the NWA-expensed solutions that are not capitalized), shown in Columns D and E. In both of these cases, the Utilities would see significantly lower earnings than either the traditional solution or the capitalized NWA solution.

Second, the utility's earnings would be higher than the traditional solution only in the case of the 30% shared savings mechanism applied to the capitalized solution. This case still produces $2.4 million in net ratepayer savings relative to the traditional solution.

Third, while the utility still has an incentive to pursue its own capitalized NWA solution, it would be close to indifferent to a third-party expensed solution, as long as the utility earns a return on the expenses (as shown in Column F). Thus, the utility should have

relatively little incentive to oppose issuing an RFP for a third-party solution if it is able to earn a return on the expensed NWA.

Q. To summarize, are you recommending that the Commission adopt a 30% shared savings mechanism and allow expensed NWAs to be capitalized?

A. Generally, yes. However, I recommend that the utility earnings and ratepayer savings under a 30% shared savings mechanism be verified using a more detailed financial model with up-to-date financial data. While the financial model that I developed is more sophisticated than the analysis that the Utilities provided in response to discovery, many of the key assumptions should be verified and adjusted to match the Utilities' actual financial data (i.e., allowed return, debt-equity ratio, taxes, loaders for administrative and general expenses, and other factors). Prior to adopting a specific sharing mechanism, I recommend that the Commission direct the utilities to file a model similar to the one I developed (submitted as Exhibit-2 to my testimony), but updated to accurately reflect the utilities' actual financial variables and calculations.

III. COST RECOVERY AND INCENTIVE PAYMENTS

RECOVERY OF NWA COSTS

Q. How do the Utilities propose to recover costs associated with NWAs?

A. The Utilities recommend that "incremental costs related to enhanced system planning activities and NWA-related costs including depreciation, return on investment, incentives, and ongoing expenses be immediately recovered in rates as part of the annual RDM price adjustment process until such time as those costs are included in base rates."[14]

Q. Do you agree with the recommendation that incremental NWA costs including depreciation, return on investment, and ongoing expenses be immediately recovered in rates?

A. No. For utility-owned NWAs, I recommend that utility investments in NWA assets and "enhanced system planning" be treated in the same manner as traditional distribution

[14] Concentric Report, p. 13.

investments. That is, I recommend that such investments enter into rates only at the time of the next rate case. To do otherwise would result in single-issue ratemaking. Single-issue ratemaking is problematic because it examines only a subset of cost categories and ignores changes in other cost centers. Only in a general rate case, where both increasing and decreasing costs are considered, should a new charge be implemented for utility-owned assets.

However, for third-party NWA solutions (which represent cost savings relative to a utility-owned solution), it may be appropriate to allow recovery of these expenses on a current basis, since this would provide some offset to the additional administrative burden that the Utilities might incur through the procurement of third-party NWA solutions.

Q. How should cost underruns and overruns be addressed?

A. Because capitalized NWA costs would be reviewed and approved at the time of the utility's next rate case, cost underruns and overruns would be addressed there. In either case, however, I recommend that the utility's incentive payment be adjusted to reflect updated NWA costs. Thus, if the NWA ends up being less expensive than originally projected, the utility would receive a larger incentive, since the overall savings to ratepayers would be larger. In contrast, if the cost of the NWA ends up being more expensive than originally projected, the utility's incentive should be reduced accordingly. This would be done at the time of the utility's next rate case following procurement of 100% of the NWA capacity.

RECOVERY OF NWA INCENTIVES

Q. Do you recommend that any incentive be recovered immediately as part of the annual RDM price adjustment process?

A. No. The incentive should only be recovered once certain benchmarks are met. Specifically, I recommend the incentive be collected through the annual RDM surcharge according to the following schedule:

Table 2. Recommended Incentive Payment Schedule

Timing	Incremental Incentive Paid	Cumulative Incentive Paid
25% Cumulative Capacity Procured	15%	15%
50% Cumulative Capacity Procured	15%	30%
75% Cumulative Capacity Procured	15%	45%
100% Cumulative Capacity Procured	15%	60%
Rate case following 100% Capacity Procurement	40%	100%

In other words, 60% of the incentive would be collected by the utility through annual RDM adjustments as NWA capacity is procured. The remaining 40% of the incentive would be retained until the utility's next rate case following 100% of NWA capacity procurement. This would allow the incentive to be updated to reflect the final costs and benefits expected from the NWA.[15]

IV. NWA IDENTIFICATION AND IMPLEMENTATION PROCESS

NWA IDENTIFICATION PROCESS

Q. How do the Utilities screen system needs for NWA suitability?

A. CMP and Emera describe their approaches to screening for NWA suitability in ODR-001-001 and ODR-002-001. They indicate that all prospective transmission and distribution projects are assessed for NWA suitability. Both utilities then limit the projects considered further to projects that are expected to cost more than $1 million. CMP also excludes from consideration needs that must be met in fewer than 3 years.

Q. Are the Utilities' approaches to screening for NWA suitability satisfactory?

A. No. The cost threshold is unnecessarily stringent for distribution projects. While the $1 million cutoff may be sensible for transmission projects, which tend to be costlier, at the

[15] The appropriate carrying cost should apply to the unrecovered incentive balance.

distribution level, lower-cost traditional solutions might feasibly be deferred or avoided with less costly NWAs.

In New York State, where the Reforming the Energy Vision proceeding has targeted the development of policies to promote non-wires alternative solutions, the large investor-owned utilities have adopted a mostly standardized NWA screening process, with all but one using a lower threshold for distribution system project eligibility of between $300,000–$500,000.[16]

Q. What cost threshold do you recommend be adopted for Emera and CMP?

A. I recommend that the cost threshold for distribution NWAs be adjusted downward so that less expensive projects are considered for non-wires alternative solutions. Specifically, I recommend that the screening threshold for distribution system projects be lowered from $1 million to $500,000. Furthermore, the existence of this lower cost bound should not completely exempt the Utilities from considering NWA solutions where they are evidently feasible at less cost than the traditional solution, even if the traditional solution is expected to cost less than $500,000.

Q. Please describe the Utilities' distribution system planning processes.

A. The distribution system planning processes for both CMP and Emera appears irregular and reactive, in contrast to the more structured transmission planning process.[17] In responses to OPA questions in docket 2016-00049, the Utilities indicated that distribution system studies are conducted on an as-needed basis, rather than on a regular basis.[18]

[16] The thresholds for consideration of NWA for each utility are, in descending order: $1 million (New York State Gas & Electric Corporation and Rockland Gas and Electric Company), $500,000 (Niagara Mohawk Corporation d/b/a National Grid), $450,000 (Consolidated Edison Company and Orange and Rockland Utilities), $300,000 (Central Hudson Gas and Electric Company), see case 16-M-0411. 2017. "Joint Utilities Supplemental Information on the Non-Wires Alternatives Identification and Sourcing Process and Notification Practices."

[17] The transmission planning process is more structured and more conducive to consideration of NWA. Should Emera or CMP determine it necessary to invest in new transmission infrastructure, the Independent System Operator requires completion of a local transmission system review and publication of a local system plan (LSP) with sufficient detail to support identification and analysis of locations where alternative solutions could defer or avoid traditional transmission investments. See ISO the Open Access Transmission Tariff (OATT) of ISO New England. Appendix 1, Attachment K. 1.2. The transmission planning process is different in the northern Maine area administered by the Northern Maine Independent System Administrator.

[18] In docket 2016-00049, in response to OPA 002-007, CMP states: "Unlike transmission system area studies, distribution system studies are not conducted on a defined interval, but rather on an exception basis as individual

Q. Do you have any concerns regarding the Utilities' planning processes and the identification of NWA opportunities?

A. Yes. It is not clear that the Utilities' current distribution system planning processes are forward-looking enough, or conducted with sufficient frequency, to adequately consider NWAs. NWAs require sufficient planning time to be feasible once distribution system needs have been identified. In the case of CMP, NWAs are not even considered as options for projects that must address a need within three years.

In addition, the current lack of transparency regarding the Utilities' planning processes provides little ability to ensure that they seriously consider non-wires alternatives in all appropriate situations.

Q. What changes would you recommend be made to the distribution system NWA screening process?

A. I recommend that CMP and Emera be required to conduct an annual distribution system study to evaluate needs over the following five years and to file the results of that study with the Commission. This would provide the Utilities with sufficient time to consider NWAs, should relevant distribution system needs be identified in the study. Such a process would also produce a formal record of NWA screenings, ensuring that the Utilities give serious consideration to these alternative solutions when appropriate. Not only would this very likely lead to greater ratepayer savings, it should also contribute to greater efficiency at the utility (with distribution planning), and may provide incremental reliability improvements because emerging distribution problems would likely be identified sooner.

distribution circuit needs dictate. Distribution Engineers at CMP perform studies on the distribution system as organic load growth rates reach equipment ratings, new block load or generation requests are received from new and existing customers, and when issues concerning the quality and reliability of electrical service warrant remediation." Likewise, in docket 2016-00049, in response to OPA 003-004, Emera states: "Distribution studies are performed regularly as needed, for example when considering new projects (e.g. new customer installations), validating contingency plans for maintenance, or to determine the impacts of other proposed projects. The Company does not have a formal schedule (e.g. 5 year, 10 year) for performing a comprehensive distribution system study."

Q. What distribution planning practices have been implemented in other states that would serve as a good model for Maine?

A. Many states are adopting more advanced distribution planning practices, with some states attempting to proactively identify means for DERs to maximize net benefits for ratepayers. For example, in 2015 California adopted a Distribution Resource Plan (DRP) process that required the utilities to, among other things, evaluate locational benefits and costs of distributed resources on the distribution system and propose mechanisms for deployment of cost-effective DERs.[19] The primary driver of the DRP process is the utilities' Grid Needs Assessment filing. This report lists the grid needs and planned investments that result from the utilities' annual planning process. Separately, the utilities must file a "Distribution Deferral Opportunity Report" that provides a list of candidate distribution deferral opportunities that result from an initial deferral screening process.

In affirming the requirement to file an annual Grid Needs Assessment (GNA) and Distribution Deferral Opportunity Report (DDOR), the California Public Utilities Commission wrote that "a main purpose of the GNA is to provide transparency into the assumptions and results of the distribution planning process that yield the candidate deferral shortlist, proposed grid modernization investments, and proactive hosting capacity upgrades proposed to accommodate forecast autonomous DER growth. This will allow the Commission and stakeholders to ensure that the candidate deferral shortlist meets the objective of maximizing ratepayer benefits of DERs."[20]

UTILITIES' PROPOSED NWA IMPLEMENTATION PROCESS

Q. Please summarize the Utilities' proposal for a process to develop and implement NWAs.

A. The Utilities propose a process that would consist of the following steps:

1. Each year, the utility would provide an Annual NWA Deployment Plan (ADP) that lists all of the NWAs that it proposes to undertake over the next year, as well as the

[19] California Public Utilities Commission, Final Guidance Assigned Commissioner Ruling on Distribution Resource Plans, Rulemaking 14-08-013, February 6, 2015.
[20] California Public Utilities Commission, Rulemaking 14-08-013, February 15, 2018, p. 33.

levelized annual savings from the NWAs, the proposed ROE incentive, and updates to savings and cost estimates. The ADP would be provided by August 1 each year.

2. The Commission Staff would have 60 days to notify the utility regarding any questions or concerns regarding the ADP (i.e., by September 30).

3. The utility would work with Commission Staff to address concerns and revise the ADP by October 31.

4. The Commission would then have two months to take action on the ADP (i.e., by December 31). If no Commission action is taken, the Utilities propose that the ADP would be "deemed reasonable given the facts and circumstances at the time."[21]

Q. What is your assessment of the Utilities' proposed implementation process?

A. The proposed implementation plan is currently deficient in several important aspects and should not be approved until important measures are added or adjusted.

Q. What measures should be added or adjusted in the implementation process?

A. I recommend that:

1) The Utilities should be required to issue an RFP for each NWA opportunity, and an independent observer should oversee the NWA evaluation and selection process.

2) The Utilities' ADPs should be automatically provided to the OPA, interested stakeholders, as well as to the Commission, and the OPA and interested stakeholders should have full participation rights in the review of the ADP, including the ability to raise questions and concerns.

3) The Utilities' proposal requests a Commission finding of prudency (implicit or explicit) regarding the proposed NWA solutions. This is not appropriate, because the Commission should never be precluded from conducting a future prudency review.

[21] Concentric Report, pp. 11-12.

4) The ADP should contain the results of a benefit-cost analysis for each new NWA project, for each NWA that was not selected, and updated benefit-cost analysis results for ongoing NWAs. The workpapers (including assumptions and calculations) should be supplied as an electronic appendix to the ADP (i.e., in spreadsheet form with an accompanying narrative).

5) The ADP should include additional details regarding the estimated costs for selected NWAs and the traditional project to be displaced, as well as measurement and verification procedures.

6) The Utilities should also submit quarterly reports for each ongoing NWA project detailing the expenditures and program activities undertaken, including all relevant details with respect to project costs, project in-service dates, incremental costs incurred, operational savings, and other benefits.

AN RFP PROCESS SHOULD BE REQUIRED

Q. Why should the NWA implementation process include an RFP process?

A. The primary objective of implementing an NWA is to provide customer benefits by reducing T&D costs. While the Utilities have a monopoly on the construction of traditional transmission and distribution infrastructure, this is not the case for NWA solutions, which may be comprised of distributed energy resources such as energy efficiency, demand response, distributed generation, and storage. There exists a robust competitive market for many types of DERs, and this competition should be harnessed when implementing NWAs for the benefit of ratepayers.

Q. What have the Utilities proposed regarding issuing an RFP?

A. In response to discovery, the Utilities state that they will likely issue RFPs or RFIs "for the foreseeable future,"[22] but do not provide a firm commitment to do so. Further, as explained by Mr. Stinneford of CMP in the October 11, 2018 technical conference, the Utilities anticipate that they may stop issuing RFPs once they have done so a few times and "have enough experience and enough data where we can make some well-informed

[22] Response to OPA-002-009 and OPA-003-008.

judgments about the cost effectiveness of alternatives without actually having to conduct an RFP."[23]

Q. Is this response sufficient to ensure that non-utility DER vendors have an opportunity to participate in the NWA process?

A. No. A technology-agnostic RFP process should be required for each NWA opportunity, even if previous solicitations were not successful in attracting viable third-party bids. This is because the market is dynamic and is characterized by rapid innovation, new entrants, and price declines. For example, the prices of lithium-ion batteries have fallen, on average, more than 20% per year from 2010 to 2017, resulting in an overall price decline of more than 80% over this period.[24]

In addition, NWAs located in different areas may provide very different opportunities for DER providers. An area with a large industrial customer base may have substantial demand response potential compared to a rural area. It should not be assumed that the results of an RFP would be similar for different NWA opportunities.

Q. Are there any other reasons why an RFP process should be required?

A. Yes. In its order in Docket 2016-00049, the Commission stated that an advantage of allowing the Utilities to procure NWAs, is that the Commission "can readily review the reasonableness of the Utilities' actions and decisions with respect to wires vs. non-wires solutions, and, on the distribution side, the Commission can disallow distribution costs that are imprudent, including costs for wires solutions that are in excess of the cost of a comparable non-wires solution."[25]

However, such a reasonableness review is limited by the information available regarding the counterfactual costs of an NWA solution. If the Utilities do not issue an RFP it would be very difficult to demonstrate that a lower cost NWA was available at the time of an investment decision. To provide the Commission with the information necessary to make

[23] October 11, 2018 transcript at 58.
[24] Bloomberg New Energy Finance, New Energy Outlook 2018, Lithium-ion Battery Price Survey, https://bnef.turtl.co/story/neo2018?teaser=true
[25] Order, Docket 2016-00049, December 15, 2017, p. 8.

a determination of reasonableness, the Utilities should be required to issue an RFP for each NWA opportunity.

THE NEED FOR AN INDEPENDENT OBSERVER

Q. You recommend that the NWA evaluation and selection process be overseen by an independent observer. Why do you recommend this?

A. The use of independent observers, monitors, or evaluators[26] is a widely adopted best practice in utility competitive procurements, particularly in situations where a utility is selecting among resource options that may include its own (preferred) solution or solutions provided by a non-regulated affiliate.[27] This is done to prevent the introduction of bias in the selection process.

For example, in California it is standard practice for solicitations to be reviewed by an Independent Evaluator for various utility procurements, including for energy efficiency.[28] Hawaii uses an independent observer to review competitive bidding processes for generation capacity.[29]

I recommend that an independent observer monitor the solicitation and evaluation process to ensure that the process is fair to all participants.

Q. Please describe the role of the independent observer.

A. To ensure that the NWA procurement process is fair and unbiased, I recommend that the independent observer:

- Monitor all communications about the solicitation to market participants, the operation of the solicitation, and the selection and negotiation process.

[26] Different terms are used in different jurisdictions, and there is a lack of a standardized definition for each. We adopt the term "independent observer" and use it to mean an independent entity who is engaged in all parts of the process to ensure fairness, primarily in an observation and reporting role, as opposed to determining the outcome of the selection process.

[27] Susan Tierney and Todd Schatzki, "Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices" (The Analysis Group, July 2008), http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/competitive_procurement.pdf.

[28] https://www.sdge.com/more-information/doing-business-with-us/energy-efficiency-third-party-solicitations

[29] Docket No. 2003-0372, Instituting a Proceeding to Investigate Competitive Bidding for Generating Capacity in Hawaii, Decision and Order No. 23121, Exhibit A - Framework for Competitive Bidding ("Framework"), filed on December 8, 2006

- Be provided with all financial information regarding the utility's proposed solution and the results of the RFP process.
- Review the evaluation criteria and selection process used in selecting the ultimate NWA or traditional wires solution.
- Be available to respond to information requests from the Commission and the OPA. These responses may be directly between the Commission or OPA and the independent observer, without any involvement or knowledge of the utility.
- File a report to the Commission describing any irregularities or concerns that the independent observer has with the procurement process. If the report contains confidential information, a public version should also be filed with confidential information redacted.

Q. How would the independent observer be selected and compensated?

A. I propose that the independent observer be selected and approved by the Commission Staff. As is common in other states, the Utilities would compensate the independent observer, but would be able to recover the fees through rates.[30]

REVIEW OF ANNUAL NWA DEPLOYMENT PLANS

Q. Why do you recommend that the OPA and other stakeholders review the ADPs?

A. It is the duty of the Public Advocate to review the reasonableness of the rates charged or proposed to be charged by any public utility, and to promote the stabilization and lowering of prices paid by customers.[31] Therefore, the OPA should be a full participant in the review of the Utilities' plans.

[30] The Analysis Group writes that "decisions about who selects the [independent observer], and to whom the [independent observer] reports may affect their independence and their ability to fulfill their duties in effective ways. In some states, [independent observers] are selected by commission staff, potentially with input from various stakeholders, including the utility and potential bidders. In other states, the utility selects the [independent observer], although the commission or its staff usually retains some control over the selection process. In nearly all states, the soliciting utility is responsible for compensating the [independent observer] and, in many states, can recover such costs from rate payers (as part of the costs of the procured resources) or through fees imposed on bidders." (Tierney and Schatzki, "Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," p. 22.)

[31] 35-A M.R.S. §17-2 (1) and (10).

In addition, other interested parties may be able to provide valuable additional information regarding NWA solutions included in the utility plans. To facilitate transparency, other relevant stakeholders should also be able to review the plans and raise questions or concerns.

Q. What do the Utilities propose regarding a Commission finding of reasonableness of their ADP?

A. The Utilities propose that, unless the Commission takes action otherwise, the ADP would be "deemed reasonable given the facts and circumstances at the time."[32] This is equivalent to requesting a determination of prudency regarding the ADP.

Q. Is the Utilities' request for a Commission finding of prudency reasonable?

A. No. The standard for prudence determinations is that a decision was reasonable. The Commission should never be precluded from conducting a future prudency review.

THE UTILITIES SHOULD PERFORM A BENEFIT-COST ANALYSIS FOR NWAS

Q. Why do you recommend the Utilities perform a benefit-cost analysis for NWAs?

A. As previously stated, the primary purpose of an NWA is to provide net benefits to utility customers. Thus, the benefits and costs of a traditional solution and an NWA should be analyzed from the perspective of utility customers as a whole, rather than simply focusing on the distribution utility's revenue requirements. This is the case because an NWA could conceivably provide ratepayer benefits beyond the local T&D system. For example, an NWA could potentially reduce the utility's ISO-NE coincident peak demand, resulting in capacity market savings, while also avoiding the need for a T&D upgrade. In this situation, both the wholesale market capacity benefits and the avoided T&D investment should be accounted for. A benefit-cost analysis is necessary to fully account for these additional benefits, as savings in the wholesale market would not be reflected in the distribution utility's comparison of the cost of an NWA to the cost of a traditional solution.

[32] Concentric Report, pp. 11-12.

Q. How do you recommend that the benefit-cost analysis be conducted, and when?

A. I recommend that each year's ADP contain a benefit-cost analysis for all NWA options evaluated, including those rejected by the utility in favor of a traditional wires solution. In addition, the ADP should contain updated benefit-cost analysis results for ongoing NWAs to reflect revised cost and benefit information.

This benefit-cost analysis should follow a standardized procedure to evaluate both solutions proposed by third parties and the Utilities' own proposed NWAs. That is, I recommend that there be a standard set of benefits that are considered in benefit-cost analysis, and standard approaches to quantifying and monetizing these benefits.

The workpapers for the benefit-cost analysis should transparently document the assumptions and calculations used in the analysis, and the workpapers should be provided as an electronic appendix to the ADP (i.e., in spreadsheet form with an accompanying narrative explaining key assumptions and data sources.)

Q. How should the standard set of benefits be developed?

A. I recommend that the Utilities propose a standard set of benefits and methodologies for quantifying these benefits. This proposal should be followed by a comment period from interested stakeholders, followed by Commission approval of a set of benefits and methodologies.

THE ADP SHOULD CONTAIN ADDITIONAL INFORMATION

Q. What additional information should be included in the ADP?

A. The ADP should include additional details regarding the estimated costs for selected NWAs and the traditional project to be displaced, as well as measurement and verification procedures.

Q. Please describe the additional cost details that should be provided.

A. Summary cost data regarding NWAs and the traditional wires solutions should be provided in the benefit-cost analyses. In addition, the Utilities should also provide a narrative that addresses any uncertainties, assumptions, or other issues in the cost data and estimation methodology.

Q. Please describe what you mean by measurement and verification procedures.

A. Measurement and verification procedures are techniques used on an ongoing basis to assess NWA performance. For example, in New York, following Commission order, Consolidated Edison Company developed measurement and verification procedures to evaluate the performance of load reduction efforts.[33]

For each NWA, the ADP should detail how impacts will be evaluated. In the event that NWA performance deviates from expected performance, or other relevant conditions have changed, a robust approach to measurement and verification can generate timely data that will support modifications. In addition, the data generated from measurement and verification procedures may inform design and management of future NWAs.

THE UTILITIES SHOULD SUBMIT QUARTERLY REPORTS FOR ONGOING NWAS

Q. What is your recommendation regarding quarterly reports for NWAs?

A. I recommend the Utilities submit quarterly reports containing information on each NWA project regarding the expenditures and program activities undertaken, including all relevant details with respect to project costs, project in-service dates, incremental costs incurred, operational savings, and other benefits.

Q. What is the rationale for this recommendation?

A. More frequent communication regarding progress on NWAs is needed to provide greater transparency into the NWA process, make necessary course corrections, and communicate lessons learned along the way.

[33] Case 15-E-0229. Non-Wires Alternatives: Implementation, Customer and Community Outreach Plan. January 30, 2017. The Joint Utilities produced a more extensive document detailing measurement and verification methodologies for energy efficiency programming. See Case 15-01319. Technical Resource Manual Management Plan. August 15, 2018.

V. EMERA'S REVENUE DECOUPLING PROPOSAL

Q. Please summarize Emera's revenue decoupling proposal.

A. Emera has proposed a revenue decoupling mechanism (RDM) that is modeled on that of CMP. The primary differences are that the proposed RDM reflects Emera's rate-class designations and other utility-specific data.[34]

Q. Do you support a revenue decoupling mechanism for Emera?

A. Yes. Revenue decoupling mechanisms can be beneficial in removing a utility's financial disincentives to NWAs and demand-side resources, as well as a utility's financial incentive to increase sales. However, it is important that revenue decoupling mechanisms be implemented with consumer protections in place.

Q. Does Emera's proposal contain consumer protection mechanisms?

A. Emera's proposal includes as a cap on annual revenue adjustments of 2%. No other consumer protection measures are included.

Q. What additional consumer protection measures should be included?

A. I recommend that the revenue decoupling mechanism should be adopted at the time of Emera's next rate case, rather than before. This will ensure that the allowed revenues contained in the RDM are appropriately based on the Company's most recent verified revenue requirements. Further, this will allow the Company's allowed ROE to be adjusted to reflect the reduced risk associated with the RDM.

VI. SUMMARY OF RECOMMENDATIONS

Q. Please provide your recommendations regarding utility NWA incentives and cost recovery.

A. I offer five recommendations regarding utility NWA incentives and cost recovery mechanisms. Specifically, I recommend that the Commission:

[34] Response to OPA-002-001.

- Reject the Utilities' proposed NWA incentive mechanism and cost recovery mechanism.
- Direct the Utilities to file a complete financial model that shows the utility earnings and ratepayer savings under various shared savings mechanisms.
- Approve a shared savings mechanism with approximately 30% savings retained by the Utilities, as well as approve the capitalization of NWA expenses.
- Allow the Utilities to recover NWA incentives only once certain capacity benchmarks are achieved, with the final incentive payments made only following the utility's next rate case.
- Allow recovery of capitalized NWA assets only beginning at the time of the utility's next rate case, but allow NWA expenses be recovered on a current basis.

Q. Please summarize your recommendations regarding the NWA planning and implementation process.

Regarding NWA identification and implementation process, I recommend that:

- The cost threshold for distribution NWAs be adjusted downward to $500,000 so that less expensive projects are still considered for non-wires alternative solutions.
- The Utilities be required to conduct an annual distribution system study to evaluate needs over the following five years.
- The Utilities be required to issue an RFP for each NWA opportunity, and an independent observer oversee the NWA evaluation and selection process.
- The Utilities make publicly available their Annual NWA Deployment Plans, and that the OPA and interested stakeholders have full participation rights in the review of the ADP, including the ability to raise questions and concerns.
- The Utilities' proposal regarding a Commission finding of prudency be rejected, as the Commission should never be precluded from conducting a future prudency review.

- The ADP contain the results and electronic workpapers of a benefit-cost analysis for each new NWA project, for each NWA that was not selected, and updated benefit-cost analysis results for ongoing NWAs.

- The ADP include additional details regarding the estimated costs for selected NWAs and the traditional project to be displaced, as well as measurement and verification procedures.

- The utilities submit quarterly reports for each ongoing NWA project detailing the expenditures and program activities undertaken, including all relevant details with respect to project costs, project in-service dates, incremental costs incurred, operational savings, and other benefits.

Q. What do you recommend regarding Emera's RDM proposal?

A. I recommend that the revenue decoupling mechanism should be adopted at the time of Emera's next rate case, rather than before, to ensure that the allowed revenues contained in the RDM are appropriately based on the Company's most recent verified revenue requirements. Further, this will allow the Company's allowed ROE to be adjusted to reflect the reduced risk associated with the RDM.

Q. Please contrast your core recommendations with the Utilities' proposal.

A. The table below contrasts the Utilities' proposal with my recommendations.

Table 3. Comparison of Recommendations to Utilities' Proposal

	Utilities' Proposal	OPA Proposal
NWA Incentive	50 to 150 bps on NWA investment, based on the ratio of 1% of the NWA investment to the expected annual savings	30% of Net Present Value of Ratepayer Savings[1]
Timing of Incentive Recovery	Not stated; presumed to be immediately	Upon completion of capacity benchmarks, with 40% withheld until following rate case to account for underruns or overruns.
Return on NWA	Only on capital investments	On all investments
Timing of Cost Recovery for Capitalized Assets	Recovered immediately through annual RDM price adjustments	No expedited recovery. Recovered beginning at next rate case

Timing of Cost Recovery for Expenses	Recovered on a current basis	Recovered on a current basis
Emera Revenue Decoupling	Implemented in 2020	Implemented at time of next rate case

Notes:

1: Shared savings percentage should be finalized based on updated incentives model

Q. Does this conclude your pre-filed testimony?

A. Yes, it does.