OLSON, BZDOK & HOWARD

January 24, 2019

Ms. Kavita Kale
Michigan Public Service Commission
7109 W. Saginaw Hwy.
P. O. Box 30221
Lansing, MI 48909

Via E-filing

RE: MPSC Case No. U-20164

Dear Ms. Kale:

The following is attached for paperless electronic filing:

Direct Testimony of Chris Neme on behalf of the Natural Resources Defense Council

Proof of Service

Sincerely,

Digitally signed by Lydia Barbash-Riley
Date: 2019.01.24 13:00:19 -05'00'

Lydia Barbash-Riley
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xc: Parties to Case No. U-20164
Ariana Gonzalez, NRDC

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **CONSUMERS ENERGY COMPANY** for reconciliation of its 2017 demand response program costs.	U-20164 ALJ Sally L. Wallace

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DIRECT TESTIMONY OF
CHRIS NEME ON BEHALF OF THE
NATURAL RESOURCES DEFENSE COUNCIL

January 24, 2019

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DIRECT TESTIMONY OF CHRIS NEME
ON BEHALF OF NRDC

I. INTRODUCTION, QUALIFICATIONS, AND PURPOSE OF TESTIMONY

Q: Please state your name, position, employer and business address.

A: My name is Chris Neme. I am a co-founder and Principal of Energy Futures Group, a consulting firm that provides specialized expertise on clean energy markets, programs and policies. My business address is P.O. Box 587, Hinesburg, VT 05461.

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

A: I am testifying on behalf of the Natural Resources Defense Council.

Q: Please describe your educational background.

A: I received a Master of Public Policy degree from the University of Michigan (Ann Arbor) in 1986. That is a two-year, multi-disciplinary degree focused on applied economics, statistics and policy development. I also received a Bachelor's degree in Political Science from the University of Michigan (Ann Arbor) in 1985. My first year of graduate school counted towards both my Masters' and Bachelor's degrees.

Q: Please summarize your business and professional experience.

A: As a Principal of Energy Futures Group, I play lead roles in a variety of energy efficiency consulting projects. Recent examples include:

- Representing NRDC in consultations with utilities and other parties in Michigan, Illinois and Ohio on a range of clean energy policy and program issues, including efficiency program and portfolio design; distribution system planning, including collaborative work with both Consumers Energy and DTE with non-wires alternatives pilot projects;

integrated resource planning; demand response; cost-effectiveness analysis of distributed energy resources; shareholder incentive mechanisms for investment in distributed energy resources; and other related topics;

- Helping the National Association of Regulatory Utility Commissioners and the Michigan Public Service Commission staff assess the relative merits of alternative approaches to defining savings goals for utility efficiency programs (focusing on lifetime rather than just first year savings);
- Serving as an appointed expert representative on the Ontario Energy Board's Evaluation and Audit Committee for natural gas demand-side management;
- Serving on the Management Committee and leading strategic planning for a team of firms, led by Applied Energy Group, that was hired by the New Jersey Board of Public Utilities to deliver the electric and gas utility-funded New Jersey Clean Energy Programs;
- Helping Green Mountain Power (Vermont) forecast the effects of strategic electrification on future electric sales, as well as to design its plan to comply with state requirements to reduce its customers' direct consumption of fossil fuels (including through electrification);
- Co-authoring the *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy-Efficiency Resources* (May 2017) and assisting state regulators and others across the country in understanding and applying the manual; and
- Leading a project for the Northeast Energy Efficiency Partnerships (NEEP) to document lessons learned from utility and other efforts across the United States over the past 25 years to use geographically targeted efficiency programs (sometimes in concert with demand

response and/or other distributed resources) to cost-effectively defer capital investment in transmission and/or distribution system infrastructure.

Prior to co-founding Energy Futures Group in 2010, I worked for 17 years for the Vermont Energy Investment Corporation ("VEIC"), the last 10 as Director of its Consulting Division managing a group of 30 professionals with offices in three states; serving on both VEIC's management team and the management team for its Efficiency Vermont project; and representing VEIC in a variety of regional forums, including the extensive series of meetings held by the Independent System Operator of New England with regional stakeholders to develop the rules for bidding of demand resources into the region's new capacity market and a prior two-year collaborative process (called New England Demand Response Initiative) in which regional stakeholders debated a range of potential regional rules and programs for acquiring cost-effective demand response resources.

During my more than 25 years in the in the industry, I have worked on clean energy policy and program issues for clients in more than 30 states, half a dozen Canadian provinces, and several European countries. A copy of my curriculum vitae is attached as Exhibit NRD-1.

Q: Have you previously filed expert witness testimony in other proceedings before the Commission?

A: Yes. I filed testimony in the following eleven other Michigan Public Service Commission Dockets:

- U-18419, regarding DTE's assessment of energy efficiency potential and its cost as part of its integrated resource plan for a proposed new gas power plant;

- U-18268, regarding DTE's proposed 2018-2019 gas energy efficiency programs (Energy Waste Reduction) plan;
- U-18262, regarding DTE's proposed 2018-2019 electric energy efficiency programs (Energy Waste Reduction) plan;
- U-18261, regarding Consumers Energy Company's proposed 2018-2021 energy efficiency programs (Energy Waste Reduction) plan;
- U-17771, regarding Consumers Energy Company's proposed amendment to its 2017 energy efficiency programs (Energy Waste Reduction) plan;
- U-17762, regarding DTE's proposed amendment to its 2017 energy efficiency programs (Energy Waste Reduction) plan;
- U-17429, regarding Consumers Energy's estimates of energy efficiency potential in its assessment of alternatives to its proposal to construct a new 700 MW gas-fired power plant (Thetford);
- U-17138, regarding Consumers Energy's proposed modifications to its 2013-2015 Energy Optimization plans;
- U-17049, regarding DTE's proposed modifications to its 2013-2015 Energy Optimization plan;
- U-16670, regarding Consumers Energy's biennial review and Amended Energy Optimization plan; and
- U-16671, regarding DTE's biennial review and Amended Energy Optimization plan.

Q: Have you been an expert witness on energy efficiency matters before other regulatory commissions?

A: Yes, I have filed expert witness testimony on more than 40 occasions before similar regulatory bodies in eleven other states and provinces, including the neighboring jurisdictions of Ohio, Illinois and Ontario.

Q: What is the purpose of your testimony?

A: My testimony reviews and critiques the shareholder incentive mechanism that Consumers Energy (hereafter referred to as "Consumers" or "the Company") is proposing for spending on its demand response programs.

Q: Are you sponsoring any exhibits?

A: Yes.

- NRD-1 Christopher Neme CV
- NRD-2 U.S. Energy Information Administration data from Form EIA-861
- NRD-3 Consumers Energy 2018 Integrated Resource Plan, Case No. U-20165, Ex A-2 (RTB-2), p. 82, Table 8.1
- NRD-4 Consumers Energy 2018 Integrated Resource Plan, Case No. U-20165, Ex A-2 (RTB-2), p. 78, Figure 8.6

II. CONSUMERS' PROPOSED DR SHAREHOLDER INCENTIVE MECHANISM

Q: What do you understand to be Consumers' shareholder incentive proposal for its demand response (DR) programs?

A: The Company's proposal can be best summarized as having the following three components:

1. **A 20% rate of return on DR capital costs**. The Company estimated that it would be earning a pre-tax return of 8.52% on such regulatory assets based on the Commission order in U-18322.[1] However, that estimate appears to have been based on the old federal corporate income tax rate. With the lowering of the federal corporate income tax rate from 35% to 21%, the pre-tax rate of return is more like 7.32%.[2] Thus, the Company's proposal is to increase the current rate of return nearly three-fold.

2. **Turning its "customer acquisition costs" into a regulatory asset and earning a 20% rate of return on that asset as well**. It is my understanding that such costs are currently just expensed.

3. **A fixed 20% payment each year for all payments made to customers who agree "to shift or shed their load."[3]** The Company states that such payments would be conditioned on the amount of DR enrolled in its programs exceeding 1.5% of the average system peak.[4]

[1] Ex A-7 (HWM-2), line 16.
[2] This is based on the capital structure and cost rates approved by the Commission in U-18322. Case No. U-18322, March 29, 2018, Order p. 46.
[3] Direct Testimony of Hubert W. Miller, p. 14, line 5.
[4] Miller Direct, p. 14, line 12.

The Company calls this proposal a combination of a "Regulatory Asset" mechanism (the first two provisions) and a "Pay-for-Performance" (or P4P) mechanism (the third provision).

Q: What rationale does the Company offer to support this Regulatory Asset plus P4P structure?

A: The Company explains that the Regulatory Asset provisions represent an "incentive to build" DR capacity while the P4P provision is an "incentive to use" that capacity.[5]

The Company further states that though its proposed 20% rate of return on the Regulatory Assets "will not necessarily put DR on an equal footing with supply-side resources, it will encourage the Company to increase investment in DR opportunities that are typically cheaper and less capital intensive than supply-side options."[6] The Company further suggests that the Regulatory Asset incentive structure is "easily calculated, tracked, and verified as part of the reconciliation process."[7]

Q: Did the Company consider other potential incentive mechanisms?

A: Yes. The Company considered several other incentive mechanisms including[8]:

- A "percent of program costs" incentive, which it categorizes as an "incentive to build";
- A "return on avoided costs" incentive, which it categorizes as an "incentive to use";
- A "shared savings" mechanism, which it also categorizes as an "incentive to use"; and

[5] Miller Direct, p. 9, Table 1.
[6] Miller Direct, p. 13, line 23 - p.14, lines 1-3.
[7] Miller Direct, p. 10, lines 5-6.
[8] Miller Direct, p. 9, Table 1.

- Several other combinations of mechanisms.

Q: Did the Company compare its proposed combination of a Regulatory Asset plus P4P to these other options?

A: To some degree. The Company generically discusses the importance of having both an "incentive to build" and an "incentive to use" DR.[9] Thus, it indirectly suggests that its proposal is better than any mechanism that does only one of those things.

The Company only directly compared its proposed combination of a Regulatory Asset plus P4P to a Shared Savings plus P4P combination. It suggests that replacing the Regulatory Asset with a Shared Savings mechanism would not be desirable because shared savings mechanisms rely upon avoided cost calculations. Consumers states that though such calculations are important to understanding how much DR should be acquired (as part of an Integrated Resource Plan, or IRP), they are not relevant to the question of whether actual DR activity was consistent with approved levels of DR acquisition. Consumers also states that avoided cost estimates can change between the time when DR resources are acquired and when they are deployed, which creates risk for utility shareholders that may dampen a utility's incentive to expand DR.[10]

The Company did identify a different combination of "incentive to build" and "incentive to use" – a Percent of Program Cost plus P4P[11] – but did not compare the relative merits of its proposal with that alternative.

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[9] Miller Direct, p. 11, lines 11-16.
[10] Miller Direct, p. 15, lines 6-13.
[11] Miller Direct, p. 9, Table 1.

III. CONCERNS REGARDING CONSUMERS' PROPOSAL

1. Overview

Q: Is the concept of establishing a shareholder incentive mechanism for DR reasonable?

A: Yes. If regulators and customers are to expect utilities to acquire the combination of resources that balances cost minimization, risk minimization, and other objectives for their customers, then it is reasonable to establish a regulatory policy framework that allows utility shareholders to make money while doing so.

In the past, utilities in Michigan and across the country were typically not able to make money by promoting or acquiring distributed energy resources, even when they were much less expensive than supply alternatives such as new power plants, new transmission lines, new capital investment in substations, or other distribution system infrastructure. That changed for energy efficiency in 2009 when the Commission first approved mechanisms allowing Michigan utilities to earn a shareholder incentive payment equal to as much as 15% of energy efficiency spending – more recently increased to 20% of energy efficiency (now Energy Waste Reduction) spending – if statutory savings goals were exceeded. DR is a little different than energy efficiency, because utilities currently *do earn* a rate of return on regulatory assets associated with capital investment in DR. However, that is only partial compensation because, unlike the peak capacity provided by a power plant, a significant portion of the cost of acquiring DR capacity is not a capital cost. Historically, that non-capital cost has simply been expensed, so the Company's shareholders did not earn anything on it. Thus, to put DR on the same conceptual footing as the alternative of new supply investments, it is reasonable to establish a mechanism that enables utility shareholders to be compensated for all forms of DR spending (capital or otherwise).

Q: Do you support Consumers' proposed shareholder incentive mechanism for DR?

A: No. As stated above, I support the concept of a shareholder incentive mechanism for DR. However, I have several concerns regarding the specifics of Consumers' proposal. At a high level, those concerns are:

- It is insufficiently tied to achievement of DR performance objectives.
- It can result in an incentive payment from customers to shareholders that is unreasonably large.

2. Insufficient Connection to DR Performance Objectives

Q: Please explain your concern about Consumers' proposal being insufficiently tied to DR performance objectives.

A: First, the two Regulatory Asset components of the Company's proposed incentive structure are not tied to the performance of the Company's DR initiatives. That is, the Company earns money for its shareholders under these two elements of its proposal; which would represent the vast majority of the total incentives the Company could earn under its proposal, simply for spending money.[12]

Also, although the Company has stated that the P4P component of its proposed DR incentive mechanism would be conditioned on achieving a performance target, that performance target –

[12] As shown in Ex A-7 (HWM-2), about three-quarters of just the 2017 incentive payments that Company would earn if its proposal were retroactively applied to 2017 DR spending would be associated with its two Regulatory Asset provisions to its proposed DR shareholder incentive mechanism. As I illustrate later in my testimony, if one considers the lifetime incentives the Company could earn on its 2017 DR spending, about 98% would be associated with the two Regulatory Asset provisions.

the peak savings potential associated with its DR enrollment exceeding 1.5% of the Company's average system peak[13] – is effectively meaningless.

Q: Why is a DR enrollment minimum requirement of 1.5% of system peak demand "effectively meaningless"?

A: First, the Company's proposed metric for its P4P "incentive to use" is not related to "using" DR. It is really a metric related to how much DR capacity the Company "built". Second, even as a performance metric for "building" DR capacity, it is inadequate. Consumers' peak demand averaged about 7338 MW over the three-year period from 2015 through 2017.[14] Thus, Consumers would simply need to maintain an annual DR capacity on the order of 110 MW in order to earn its P4P incentive. However, according to its 2018 IRP, the Company is expecting to have 349 MW of DR resources (nearly 5% of recent peak demands) enrolled in 2019, with an average of 49 additional MW of DR capacity to be added each year through the year 2030 (at which point total DR capacity would be over 1100 MW).[15] In other words, the Company's proposed performance metric for the P4P incentive is only a very small fraction (about one-third) of its current (2019) need, and an even smaller fraction of what it forecasts it will need in future years.

Q: Why is it important for shareholder incentives for DR to be tied to meaningful performance targets?

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[13] Miller Direct, p. 14, lines 10-12.

[14] Ex NRD-2, U.S. Energy Information Administration data, from Form EIA-861. See "operational data" Excel files within the zipped files at https://www.eia.gov/electricity/data/eia861/, which show Summer Peak demand for Consumers as 7231 MW in 2015, 7635 MW in 2016 and 7057 MW in 2017.

[15] Ex NRD-3, Consumers Energy 2018 Integrated Resource Plan, Case No. U-20165, Ex A-2 (RTB-2), p. 82, Table 8.1.

A: The underlying premise for shareholder incentives for DR is that the Company needs to be encouraged to optimize the amount of cost-effective DR that it acquires and uses. Thus, it does not make sense to establish a performance incentive that is not directly tied to actually achieving the economically optimal level of DR capacity and then using that capacity when it can help the Company's customers to save money.

Q: Why doesn't the Company's proposed "incentive to build" – i.e., its proposed 20% rate of return on Regulatory Assets associated with both DR capital costs and DR acquisition costs – create an incentive to optimize the amount of DR capacity on its system?

A: Under the Company's proposal, it would earn a substantial incentive on DR capacity it builds and/or maintains, regardless of how much it builds and whether or not the amount that it builds is consistent with its IRP.

Q: What would be a reasonable performance metric for an "incentive to build"?

A: As I noted earlier, the Company's IRP suggests that it should be growing its DR capacity by an average 49 MW per year for every year between 2019 and 2030.[16] In that context, any shareholder "incentive to build" should be tied to achievement of the incremental annual growth in DR capacity that the IRP suggests is needed. That should be the case regardless of the form of the incentive.

For example, if the shareholder incentive is structured as a bonus rate of return for a Regulatory Asset, the maximum rate of return should not be earned unless the full incremental annual

[16] Note that the 49 MW is an average annual value. While the Figure 8.6 (p. 78) of the Company's IRP suggests that the growth in DR should be at least roughly linear, it is not possible to discern from the graph whether it is exactly linear. Ex NRD-4 (Consumers Energy 2018 Integrated Resource Plan, Case No. U-20165, Ex A-2 (RTB-2), p. 78, Figure 8.6). The DR performance target for each year should be equal to the actual IRP forecast growth in DR capacity for that year.

growth in DR capacity forecast to be needed in a given year (i.e., about 49 MW of growth per year on average) is achieved; the rate of return should decline as the gap between the desired DR capacity growth and the actual capacity growth increases. Similarly, if the shareholder incentive to build is structured as a one-time annual payment expressed as a percent of DR participant acquisition costs, that percentage should be maximized only if the desired DR capacity growth of 49 MW (or whatever the precise amount forecast to be needed for a given year in the IRP) is achieved; the shareholder incentive percentage should decline as the gap between the desired DR capacity growth and the actual DR capacity growth increases.

In addition, there would be merit to linking part of the "incentive to build" to the potential acquisition of DR in specific geographic locations in order to help cost-effectively address localized distribution system needs – acquiring DR not just for system capacity needs, but as part of a lower-cost approach to addressing a localized reliability concern (e.g., deferring a more expensive upgrade of a substation as part of a "non-wires alternative"). Such an incentive would encourage the Company to recognize and pursue potential benefits of DR that it has historically not attempted to capture for its customers.

Q: What would be an appropriate performance metric for an "incentive to use"?

A: To answer that question, it is important to consider the ways in which DR capacity could be deployed to cost-effectively meet customers' needs and to identify which of those opportunities might actually merit an incentive. At a high level, there are two ways in which DR that has been built could be used:

- To address a reliability need – i.e., when DR resources are needed to meet system peak demand and/or peak demand in a specific geographic area to address a specific distribution system need; and
- For economic dispatch, to cost-effectively reduce the amount of electricity that needs to be purchased during high cost hours.

While the Company may need an incentive to build enough DR capacity to meet reliability needs cost-effectively, once that capacity is "built" (or acquired), it is unclear why the Company would need an incentive to actually use it to address reliability needs. If the Company had acquired DR capacity but chose not to use it in the context of a reliability need, and therefore did not "keep the lights on", there would undoubtedly be major repercussions from regulators and customers. Put another way, the Company already has a strong incentive to use DR capacity that has already been built to meet reliability needs.

On the other hand, there may be value to an incentive to use DR capacity to avoid paying for very expensive electricity (when the cost of using or dispatching existing DR capacity is lower than the cost of buying electricity).

3. Proposed DR Incentives Are Too Large

Q: Why do you consider the magnitude of the potential DR shareholder incentive under Consumers' proposal to be too large?

A: In a nutshell, per dollar spent, the Company's proposal would enable it – over time – to earn substantially more shareholder incentives for DR than for energy efficiency.

Q: How much more would the Company earn for DR under its proposal than it can earn for energy efficiency?

A: In Exhibit A-7 (HWM-2), Consumers witness Miller shows how much the Company would earn in shareholder incentives in 2017, if its proposed mechanism were applied retroactively to that year. The total incentive – $1.46 million – represents about 9% of its $16.4 million total DR spending in 2017. However, that is not the total incentive the Company would earn on its 2017 spending because the Company would continue to earn incentives on most of its 2017 DR spending (the 89% of it that would become a Regulatory Asset) for about another 25 years. Indeed, as shown in the table below, I estimate that the net present value (NPV) of the Company's total incentive associated with just its 2017 DR spending would be $18.54 million. That is 113% of its 2017 DR spending, or an incentive that is more than five times what the Company can earn on its annual energy efficiency program spending.

Table 1: NPV of Consumers' DR Incentive Proposal as Applied to 2017 DR Spending[17]

		Related Line from Consumers Exh A-7 (HWM-2)	Incentive Payments Associated with 2017 DR Spending: Payments Received in Calendar Year 2017	Incentive Payments Associated with 2017 DR Spending: NPV of Incentives Received over Life of 2017 Cost Recovery
Program Expenses				
	Customer Acquisition (O&M)	1	$7,107,634	$7,107,634
	Equipment Cost	2	$7,463,706	$7,463,706
	Customer Payments	3	$1,828,727	$1,828,727
	Total	4	$16,400,067	$16,400,067
Shareholder Incentives				
	DR Customer Acquisiton return	10	$683,470	$10,909,138
	DR Capital Bonus Return	18	$455,028	$7,262,885
	DR Customer Payment	21	$365,745	$365,745
	Total	22	$1,504,244	$18,537,769
	Total as % of 2017 spend	n.a.	9%	113%

Q: What are the key factors that cause the NPV of incentives to shareholders to be such a large fraction of annual DR spending?

A: There are three key drivers. The two most obvious are (1) turning the DR customer acquisition costs into a Regulatory Asset; and (2) the size of Consumers' proposed pretax rate return (i.e., 20%) on both Regulatory Assets. The third and perhaps less obvious factor is the assumed depreciation rate. For example, if the 20% rate of return proposed by the Company is accepted, but both the capital costs and customer acquisition costs were depreciated over 10 years instead of the roughly 26 years proposed by the Company, the NPV of shareholder

[17] Consistent with Consumers witness Miller's calculations in Ex A-7 (HWM-2), my calculations of the NPV of the incentives associated with the Company's DR capital spending conservatively include only the value of only the *increased* return – i.e., the difference a 20% return and the Company's normal return. NPVs were computed using a pretax weighted average cost of capital (WACC) of 7.32%, which I computed using the Commission U-18322 approved post-tax WACC of 5.89%, converted to pre-tax WACC using the current federal corporate income tax rate of 21% rather than the old 35% that Mr. Miller used when he computed a normal return of 8.52%. That is why the first year payments in my table are slightly higher than those in Ex. A-7 (HWM-2). Though the old federal tax rate would apply to 2017, I have made this change to illustrate the future impacts of Consumers' proposed incentive structure. Note also that though the value of the incentives might change with more up to date values for pretax WACC, any assumption changes will not alter the fundamental conclusions that the NPV of lifetime incentives associated with just one year of DR spending under the Company's proposal are (1) much greater than just the first year of payments and (2) a much higher percent of DR spending than can be earned for energy efficiency programs.

incentive would be cut nearly in half, representing 60% of annual spending instead of 113% under the Company's proposal. However, that is still three times the incentive level – as a percent of annual spending – that the Company can earn for its efficiency programs.

Q: Isn't the Company contending that its proposed DR incentive would only partially reduce the disparity in return to shareholders between investment in DR and investment in new generating capacity?

A: Yes. Consumers witness Miller states that the Company's proposed "enhanced return on DR capital expenses is intended to partially rectify the disparity that exists between investing capital in demand-side versus supply-side resources."[18] He goes on to explain, by way of example, that "a 20% return on $10 million is much less attractive to shareholders than a 10% return on $500 million."[19] The implication is that the ultimate objective should be to move towards parity in the *absolute dollars* of shareholder incentive earned from DR investments versus those earned from the alternative of new generating capacity.

Q: Wouldn't it make sense for a utility's shareholders to earn just as much on DR in absolute dollars as on a new gas power plant or other alternatives?

A: No. That is analogous to suggesting that utilities should make as much profit on a gas-fired power plant as they would on a much more expensive nuclear power plant of comparable capacity – or that they should earn as much from a cost-conscious substation upgrade as from a more expensive one that provided no greater benefit (i.e., that wasted money). As regulated monopolies, Michigan's investor-owned utilities have an obligation to provide least cost service

[18] Miller Direct, p. 16, lines 1-3.
[19] Miller Direct, p. 16, lines 3-4.

to their customers (while balancing risk, reliability, and other objectives). In that context, it is not reasonable to suggest that the total dollar value of profits for any investment should be the same as for more expensive alternatives that could be otherwise procured to meet the same need.

Q: What would be an appropriate way of assessing how large a shareholder incentive may be appropriate for DR?

A: I would suggest starting by ensuring that magnitude of shareholder incentives in distributed energy resources be at least equal *per dollar of investment* (not absolute dollars) as supply alternatives. Some level of "bonus" incentive – again per dollar of investment – may be appropriate for achieving economically optimal levels of distributed resource capacity. The magnitude of any such bonuses should depend on the nature of any financial disincentives, risks, and other factors associated with procuring the distributed energy resource in question. The incentive for meeting 1.5% new energy efficiency savings each year is 20% of efficiency program spending. Generally speaking, I would suggest that the financial disincentives for utilities to pursue DR are lower than the disincentives to pursue energy efficiency because DR does not produce the level of lost revenues (from reduced energy sales) that energy efficiency produces. Thus, I would suggest that the incentives that the Company can earn for DR should be a little lower – per dollar of spending – than those they can earn for energy efficiency (i.e., less than 20% of spending).

IV. ALTERNATIVE PROPOSED DR INCENTIVE STRUCTURE

Q: Have you developed an alternative to the shareholder incentive mechanism that Consumers has proposed for DR?

A: Yes. I suggest the following shareholder incentive structure for Consumers' DR investments for 2019 and 2020:

1. **Annual Payment of Up to 13% of Non-Capitalized DR Costs for Achieving DR Capacity Growth Targets.** Non-capitalized DR costs include both what the Company calls "customer acquisition costs" and "customer incentive payments". No incentive would be paid if the Company failed to reach 50% of its DR capacity growth target. The Company would earn an incentive equal to 0.26% of its non-capitalized DR costs for every 1% above 50% of its DR capacity growth target that it achieved, up to the 13% maximum incentive for achieving or exceeding its target.

2. **Annual Payment of 2% of Non-Capitalized DR Costs for Assessment of DR as Part of Potential Non-Wires Alternatives (NWA)**. The Company could earn a single annual incentive payment equal to 2% of non-capitalized DR costs incurred each year if it demonstrates that it assessed DR as part of a potential NWA solution for at least five distribution system projects in a given year. Demonstrating assessment of DR as part of NWA solutions would require each of the following be accomplished each year by the Company:

    a. Identification of distribution system projects which have the potential to be candidates for an NWA solution using appropriate Site Location Selection

Criteria (e.g., magnitude of load relief required, timeframe by which load relief is required, magnitude of the cost of the distribution solution, etc.);

b. Subsequent analysis for at least five NWA candidates each year of:

i. The amount of DR and other distributed energy resources (DERs), including efficiency, that could be acquired over time in the geo-targeted areas served by the potential distribution system projects identified in (a);

ii. The cost of acquiring and deploying the DR and other DERs in those geo-targeted areas;

iii. Whether the estimated DR and other DER potential in the geo-targeted areas would be sufficient to defer the investment in the traditional distribution system solutions; and

iv. Whether the deferrals would likely be cost-effective.

c. Documentation by the Company that it has put in place all systems (hardware, software, and decision-making protocols) necessary to dispatch/deploy DR solely in the geographic areas targeted by NWAs.

Note that the Company would also earn its normal rate of return on capital investments associated with DR.

Q: You suggest this structure for 2019 and 2020. How might it change after that?

A: There may be several reasons for refining the structure after 2020. First, it may be appropriate to consider developing an incentive to encourage "economic dispatch" of DR. For example, it may be appropriate to allow the Company to earn an annual incentive equal to the lesser of a fixed percentage of the cost savings (energy cost savings minus the marginal cost of dispatching DR) associated with economic dispatch of DR during the year and 3% of total non-capitalized DR costs incurred that year. If such an incentive were added, the maximum 13% of non-capitalized spending I have proposed for meeting the DR capacity growth target (part 1 above) could be reduced by the same amount (e.g., from 13% to 10%) to keep the total maximum incentive on non-capitalized spending (15%) unchanged. Such a modification might be appropriate for 2019 or 2020. I would propose estimating the average annual number of hours during which economic dispatch of DR might make sense, and the potential cost savings associated with economic dispatch during those hours, in order to establish reasonable parameters for the metric.

Second, the NWA performance metric should be revisited. Specifically, it may be appropriate to transition it to a metric based on actual deployment of DR as part of NWAs, rather than just planning and analysis of DR as part of NWAs. Alternatively, if the regulatory framework for distribution system planning has evolved to the point where appropriate financial incentives for broader consideration of NWAs has been put in place by the Commission, it may be appropriate to eliminate the metric altogether and to then move 2% of non-capitalized DR spending bonus to the second element of the Incentive to Build described above (that would increase the maximum incentive in part 1 of my proposal above from 13% to 15%, or from 10% to 12% if the economic dispatch metric described above is established).

Q: Please summarize why you believe this proposal is preferable to the one Consumers proposed.

A: First, it ties the amount of shareholder incentive that the Company earns to appropriate performance metrics:

1. The amount of added DR capacity it needs to add to be consistent with its IRP; and

2. Demonstrated consideration of deployment of DR to take advantage of a potentially valuable new benefit of DR – deferring distribution system investments.

Second, though the maximum incentive the Company could earn is substantial, it is more reasonable than what the Company proposed. It is also more consistent with the level of incentive that could be earned from meeting annual energy efficiency goals.

Q: Does this conclude your testimony?

A: Yes.

ENERGY FUTURES GROUP

CHRISTOPHER NEME, PRINCIPAL

EDUCATION

M.P.P., University of Michigan, 1986
B.A.., Political Science, University of Michigan, 1985

EXPERIENCE

2010-present: Principal (and Co-Founder), Energy Futures Group, Hinesburg, VT
1999-2010: Director of Planning & Evaluation, Vermont Energy Investment Corp., Burlington, VT
1993-1999: Senior Analyst, Vermont Energy Investment Corp., Burlington, VT
1992-1993: Energy Consultant, Lawrence Berkeley National Laboratory, Gaborone, Botswana
1986-1991: Senior Policy Analyst, Center for Clean Air Policy, Washington, DC

PROFESSIONAL SUMMARY

Chris specializes in analysis of markets for energy efficiency, renewable energy and strategic electrification measures and the design and evaluation of programs and policies to promote them. During his 25+ years in the clean energy industry, Mr. Neme has worked for energy regulators, utilities, government agencies and advocacy organizations in 30 states, 6 Canadian provinces and several European countries. He has defended expert witness testimony before regulatory commissions in ten different jurisdictions; he has also testified before several state legislatures.

SELECTED PROJECTS

- ***Natural Resources Defense Council (Midwest).*** Critically review efficiency plans, distribution system plans, and demand response plans filed by Illinois, Michigan and/or Ohio utilities. Draft and defend regulatory testimony on critiques. Represent NRDC in stakeholder-utility processes governing plan and goal development and related policies. Provide technical support to collaborative efforts with utilities to design and launch non-wires alternative pilot projects. Supported development of Illinois Future Energy Jobs Act. (2010 to present)
- ***New Jersey Board of Public Utilities.*** Serve on management team responsible for statewide delivery of New Jersey Clean Energy Programs. Lead strategic planning; support regulatory filings, cost-effectiveness analysis & evaluation work. (2015 to present) Served on management team for start-up of residential and renewables programs for predecessor project. (2006-2010)
- ***E4TheFuture.*** Co-Authored 2017 National Standard Practice Manual for assessing cost-effectiveness of energy efficiency and other distributed resources. Assisting state regulators and others in understanding and applying the Manual. (2016-present)
- ***Regulatory Assistance Project - U.S.*** Provide guidance on efficiency policy and programs. Lead author on strategic reports on achieving 30% electricity savings in 10 years, using efficiency to defer T&D system investments, & bidding efficiency into capacity markets. (2010 to present)
- ***Ontario Energy Board:*** Serve on provincial gas DSM Evaluation Committee, advisory committee on gas efficiency potential study and advisory committee on carbon price forecast. (2015-present) Served on predecessor utility-stakeholder evaluation committees. (2000 to 2015)

CHRISTOPHER NEME, PRINCIPAL

- *Green Energy Coalition (Ontario).* Represent coalition of environmental groups in regulatory proceedings, utility negotiations and stakeholder meetings on DSM policies (including integrated resource planning on pipeline expansions) and utility proposed DSM Plans. (1993 to present)
- *New Hampshire Consumer Advocate.* Filed expert witness testimony on the merits of including a non-wires alternative pilot project in the state's efficiency program plans. (2018)
- *Southern Environmental Law Center.* Critically reviewed and filed expert witness testimony on Duke Energy efficiency program plans and past year savings claims. (2018)
- *Green Mountain Power (Vermont).* Support development and implementation of GMP's compliance plan for Vermont RPS Tier 3 requirement to reduce customers' direct consumption of fossil fuels, with significant emphasis on strategic electrification strategies. Also led development of forecast of strategic electrification potential. (2016 to 2018)
- **Toronto Atmospheric Fund.** Helped draft an assessment of efficiency potential from retrofitting of heat pumps into electrically heated multi-family buildings (2017).
- *Regulatory Assistance Project - Europe.* Provide on-going support on efficiency policies and programs in the United Kingdom, Germany, and other countries. Reviewed draft European Union policies on Energy Savings Obligations, EM&V protocols, and related issues. Drafted policy brief on efficiency feed-in-tariffs and roadmap for residential retrofits. (2009 to 2017)
- *Northeast Energy Efficiency Partnerships.* Helped manage Regional EM&V forum project estimating savings for emerging technologies, including field study of cold climate heat pumps. Led assessment of best practices on use of efficiency to defer T&D investment. (2009 to 2015)
- *Ontario Power Authority.* Managed jurisdictional scans on leveraging building efficiency labeling/disclosure requirements and non-energy benefits in cost-effectiveness screening. Supported staff workshop on the role efficiency can play in deferring T&D investments. Presented on efficiency trends for Advisory Council on Energy Efficiency. (2012-2015)
- *New Hampshire Electric Co-op.* Led assessment of the co-op's whole building efficiency retrofit, cold climate heat pump and renewable energy programs. (2014)
- *National Association of Regulatory Utility Commissioners (NARUC) and Michigan Public Service Commission.* Assessed alternatives to first year savings goals to eliminate disincentives to invest in longer-lived measures and programs. (2013)
- *New York State Energy Research and Development Authority (NYSERDA).* Led residential & renewables portions of several statewide efficiency potential studies. (2001 to 2010)
- *Ohio Public Utilities Commission.* Senior Advisor developing a new TRM. (2009 to 2010)
- *Vermont Electric Power Company.* Led residential portion of efficiency potential study to assess alternatives to new transmission line. Testified before Public Service Board. (2001-2003)
- *Efficiency Vermont.* Served on Sr. Management team. Supported initial project start-up. Oversaw residential planning, input to regulators on evaluation, input to regional EM&V forum, development of M&V plan and other aspects of bidding efficiency into New England's Forward Capacity Market (FCM), and development and updating of nation's first TRM. (2000 to 2010)

	A	B	C	D	E	F	G	H
1	**Utility Characteristics**						**Demand**	
2							**(Megawatts)**	
3	**Data Year**	**Utility Number**	**Utility Name**	**State**	**Ownership Type**	**NERC Region**	**Summer Peak Deman**	**Winter Peak Deman**
42	2015	392	Alpena Power Co	MI	Investor Owned	RFC	60.0	55.0
374	2015	4254	Consumers Energy Co	MI	Investor Owned	RFC	7,231.0	5,573.0
443	2015	5109	DTE Electric Company	MI	Investor Owned	RFC	10,660.0	7,594.0
1735	2015	19578	Upper Peninsula Power Company	MI	Investor Owned	RFC	93.0	102.0

	A	B	C	D	E	F	G	H
1	**Utility Characteristics**						**Demand**	
2							**(Megawatts)**	
3	**Data Year**	**Utility Number**	**Utility Name**	**State**	**Ownership Type**	**NERC Region**	**Summer Peak Deman**	**Winter Peak Deman**
42	2016	392	Alpena Power Co	MI	Investor Owned	RFC	63.0	53.0
371	2016	4254	Consumers Energy Co	MI	Investor Owned	RFC	7,635.0	5,271.0
440	2016	5109	DTE Electric Company	MI	Investor Owned	RFC	11,422.0	7,404.0
1730	2016	19578	Upper Peninsula Power Company	MI	Investor Owned	RFC	131.0	129.0

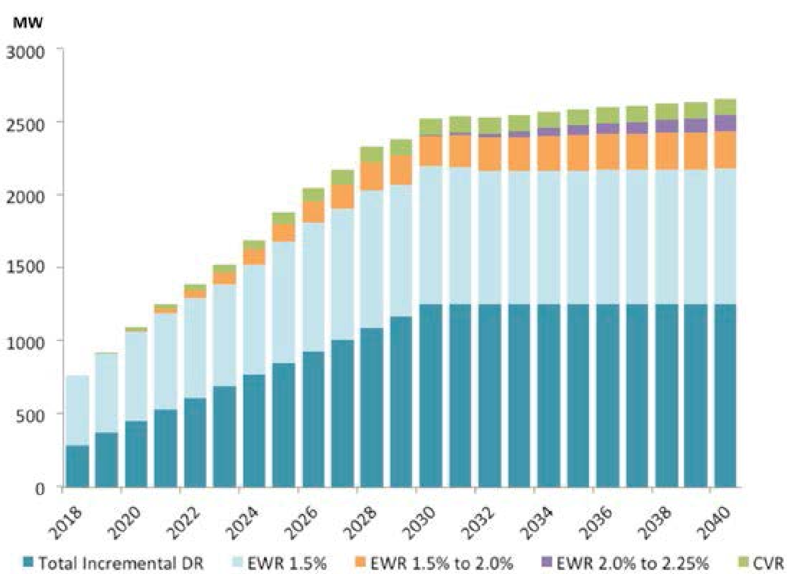
	A	B	C	D	E	F	G	H
1	**Utility Characteristics**						**Demand**	
2							**(Megawatts)**	
3	**Data Year**	**Utility Number**	**Utility Name**	**State**	**Ownership Type**	**NERC Region**	**Summer Peak Deman**	**Winter Peak Deman**
42	2017	392	Alpena Power Co	MI	Investor Owned	RFC	61.0	55.0
370	2017	4254	Consumers Energy Co	MI	Investor Owned	RFC	7,057.0	5,458.0
439	2017	5109	DTE Electric Company	MI	Investor Owned	RFC	10,554.0	7,177.0
1726	2017	19578	Upper Peninsula Power Company	MI	Investor Owned	RFC	134.0	128.0

Source: Operational_Data_2017.xlsx; Operational_Data_2016.xlsx; and Operational_Data_2015.xlsx which can be found at https://www.eia.gov/electricity/data/eia861/

Table 8.1: Growth and performance of the demand response and energy waste reduction programs projections

DEMAND-SIDE RESOURCE	MW REDUCTIONS			MISO ZRC		
Planning Year	2019	2030	2040	2019	2030	2040
AC Cycling	44	104	104	49	116	116
Commercial & Industrial	120	290	290	135	325	325
Rate GI provision	137	137	137	154	154	154
Rate EIP	48	48	48	54	54	54
Energy Waste Reduction	0	218	361	0	226	373
Conservation Voltage Reduction	11	111	111	11	115	115
New Incremental DR	0	539	539	0	605	605

Figure 8.11 DSM Projected MW Reductions from 2018 levels



MARKET PURCHASES

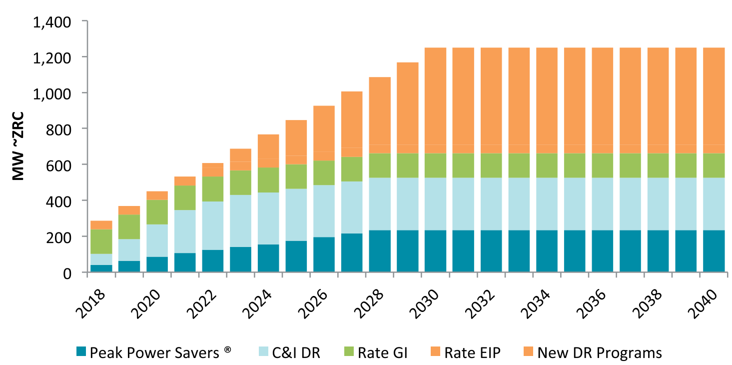
Each day, the company bids all of its generating units into the market and purchases all of its demand from the market. During the summer of 2017, we established load and price triggers to guide our dispatch of demand resources, as mentioned in the 'Dispatch for Demand Resources' section above. Because our Demand Response resources allow for only a limited number of events per season (10 for A/C cycling and 14 for TOU pricing), there are many days a DR event can be called, but are limited by the number of events that can be called.

FORECASTED DEMAND REDUCTIONS

The Residential and Business DR programs are expected to continue to grow over time reaching a level of 430 MW (479 ZRC) by the year 2023 and 525 MW (577 ZRC) by the year 2028, respectively, and maintained at these levels throughout the IRP study period. The Rate GI provision and EIP rate are at 137 MW (154 ZRC) and 48 MW (54 ZRC), respectively, for each year of the IRP study period.

The proposed course of action includes about 540 MW of incremental DR to the existing DR program levels at an average cost of $19.5 million from 2022 through 2040. As the company continues to learn and expand existing programs this incremental level of DR provides flexibility to design a new program or modified program fitting customers' needs. New incremental DR levels begin in the year 2022 and reach the 540 MW level by the year 2030 to meet our greatest time of capacity need and are a blend of behavioral and direct control programs such as capacity bidding and TOU. This scale up of new programs gives our experts time to learn, adjust and optimize the value of DR programs offered to customers, and incorporate potential policy changes such as all customers on TOU rates.

Figure 8.6: Projected demand response reductions



Total projected capital spend from 2019 through 2040 for existing and incremental DR averages $5.8 million per year, totaling around $127 million by 2040. The total projected O&M costs averages to $35 million per year, totaling around $776 million by 2040. The projected O&M assumes all costs associated with the new incremental DR is O&M. Depending upon the actual design of these programs a portion of these costs may shift to capital spend. The cost projections are based upon the expertise of our subject matter experts for existing programs and the statewide potential study conducted by the MPSC in 2017, and are viewed as cost-effective for customers. The level of load reduction is aligned with the achievable potential levels in both the utility and MPSC demand response potential studies.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **CONSUMERS ENERGY COMPANY** for reconciliation of its 2017 demand response program costs.	U-20164 ALJ Sally L. Wallace

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PROOF OF SERVICE

On the date below, an electronic copy of **Direct Testimony of Chris Neme on behalf of NRDC** was served on the following:

Name/Party	E-mail Address
Administrative Law Judge Sally L. Wallace	Wallaces2@michigan.gov
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Counsel for MPSC Staff Heather Durian Daniel Sonneveldt	durianh@michigan.gov sonneveldtd@michigan.gov

The statements above are true to the best of my knowledge, information and belief.

OLSON, BZDOK & HOWARD, P.C.
Counsel for NRDC

Date: January 24, 2019

By: Karla L Gerds
Digitally signed by Karla Gerds
DN: cn=Karla Gerds, o=Olson, Bzdok & Howard, P.C., ou, email=karla@envlaw.com, c=US
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