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STATE OF NEW HAMPSHIRE

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NHPUC 31OCT'19PM4:07

October 31, 2019

Ms. Debra A. Howland
Executive Director
New Hampshire Public Utilities Commission
21 South Fruit Street
Concord, NH 03301

Re: IR 15-296 Investigation into Grid Modernization

Dear Ms. Howland:

Staff encloses a memorandum on the recent Stakeholder process for filing with the Commission today. For ease of review, Staff has inserted comments by Stakeholders in footnotes within the text of its memorandum. Comments are also attached to the memorandum for reference. Also attached is Staff's proposed baseline data and capabilities document.

Of the technical session participants, only Clean Energy New Hampshire, Conservation Law Foundation, and the New Hampshire Department of Environmental Services commented on the Staff Memorandum. The Office of the Consumer Advocate did not file comments on the Staff Memo, but reserved the right to file comments later. The Joint Utilities, City of Lebanon, Direct Energy, and Pat Martin did not provide comments on the Staff Memo.

Very truly yours,

/s/ F. Anne Ross	*/s/ Brian D. Buckley*
F. Anne Ross	Brian D. Buckley
Staff Attorney	Staff Attorney

Cc: Service List
Stakeholder List
Attachments

STATE OF NEW HAMPSHIRE

Inter-Department Communication

DATE: October 31, 2019
AT (OFFICE): NHPUC

FROM: Leszek Stachow
Anne Ross
Liz Nixon
Kurt Demmer
Brian Buckley

SUBJECT: IR 15-296 Staff Report on Technical Sessions
Order No. 26,254 (May 29, 2019)

TO: Commissioner Bailey
Commissioner Giaimo
Debra Howland, Executive Director

Comments and Technical Sessions

Following written comments filed on September 6, 2019, representatives of the following Stakeholders met in two technical sessions, held at the Commission on September 19, and October 10, 2019.

Eversource Energy
Unitil Energy Systems
Liberty Utilities
Clean Energy NH (CENH)
Conservation Law Foundation (CLF)
NH Department of Environmental Services (DES)
City of Lebanon
Office of the Consumer Advocate (OCA)
Direct Energy
Pat Martin

The two technical sessions on September 19, and October 10, 2019, were facilitated by David Littell, senior advisor for the Regulatory Assistance Project. Mr. Littell focused discussion at the technical sessions on the 11 topics identified in Order No. 26,254 (May 29, 2019).

1. Cost Effectiveness Methodology
2. Utility Cost Recovery
3. Utility and Customer Data and Third Party Access
4. Hosting Capacity/Locational Value Analysis/Interconnection
5. Annual Reporting Requirements
6. Rate Design Policy
7. Strategic Electrification Policy
8. Consolidated Billing/General Billing
9. Consumer Advisory Council/Stakeholder Engagement
10. Capital Budgeting Process
11. Least Cost Integrated Resource Plan (LCIRP)/Integrated Distribution Plan (IDP) Integration

In addition, the OCA invited Stakeholders to a separate meeting on October 9, 2019, at which the Wired Group (OCA's expert) presented more detail concerning the OCA's proposal.

Issues Where Limited Consensus is Possible.

The OCA has indicated that it will be filing comments separately. Throughout the rest of this memo, when Stakeholders are mentioned, OCA is not included in the reference. Nonetheless, based on discussions among Stakeholders at the two technical sessions, other Stakeholders appeared to agree on some aspects of these issues and proposed that a list of areas where agreement might be reached be circulated for consideration. Staff has circulated this memo to identify those issues for consideration, incorporated a description of Stakeholder comments into footnotes within this memo, and provided the comments as an attachment to this memo.

3. Utility and Customer Data and Third Party Access

Stakeholders agreed that customer data would be dealt with in a separate Commission docket pursuant to SB 284 (2019).[1]

Stakeholders agreed that baseline data is needed for each utility distribution system prior to filing of the IDPs to help inform Stakeholder input for utility preparation of the IDPs, and that data should be provided on an individual circuit level, though some utilities noted they may not have baseline data for every individual circuit yet.

Staff developed a straw proposal identifying elements of the required baseline data and capabilities, and circulated that proposal to the Stakeholders for comment. Comments received by the time of this filing were incorporated into the final baseline data and capabilities document, which is attached to this memorandum.

[1] In its comments, CLF suggests that keeping the docket on customer data connected to grid modernization efforts will be important.

4. Hosting Capacity/Locational Value Analysis/Interconnection

Stakeholders agreed that a standing working group should be created before utility IDPs are filed and should remain in place for a period of time in order to receive data and information on each utility's progress on hosting capacity analysis and presentation, locational valuation initiatives, and interconnection procedures.[2, 3]

Stakeholders noted that the separate locational value study taking place in Docket No. DE 16-576 also focusses on locational valuation. The IDP planning process may benefit from the data prepared for that process and associated study. There may be synergies between the study and Stakeholder engagement process already underway in DE 16-576 and the tasks of this IDP working group envisioned to address hosting capacity, locational value, and interconnection issues in IR 15-296.

5. Annual Reporting Requirements

Stakeholders agreed that annual reports on the utility distribution systems would be appropriate. The specific data that will be included in these reports remains open.

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[2] In its comments, CENH suggests that the role of such a working group or standing technical committee should not be limited to the passive receipt of information and instead envisions a truly collaborative process between utilities and DER developers to improve existing interconnection procedures and plan ahead to avoid future interconnection limitations and delays, in addition to making available detailed hosting capacity information. Its comments further suggest that a working group should aim to create consistency between the three utilities interconnection application, review, and queue process with a goal of increasing information sharing between developers and utilities to reduce work burden and any potential interconnection delays. This working group would also be an appropriate venue to develop tiered interconnection queues and develop a shared cost approach to multiple DER projects proposing to connect in close proximity.

[3] In its comments, CLF concurs with CENH that the working group must do more than receive information from the utilities, and instead supports a collaborative process that includes a broad range of Stakeholders aimed at improving interconnection procedures and planning to avoid limitations and delays in deploying DER, in addition to access to detailed hosting capacity information. They further concur that the working group could increase consistency among the utilities interconnection application, review, and queue management processes and increase information sharing between developers and utilities.

6. Rate Design Policy

Stakeholders agreed that rate design should be addressed as part of a rate case, and supported utility pilots on new rate design approaches as a way to test the effectiveness of new rate designs that could be adopted in a rate case.[4, 5]

7. Strategic Electrification Policy

Stakeholders agreed that the Commission's IDP process is not a vehicle for setting policy on strategic electrification, but agreed that each utility should, in its load and peak forecasts, predict the level of incremental electrification in its service territory as part of its IDP. Further SB 575(2018) requires the Commission to consider rate design standards for electric companies, including time of day rates for charging electric vehicles for both residential and commercial customers, as well as interruptible rates, demand charges, load management and seasonal rates.[6]

[4] In its comments, CENH acknowledges that Stakeholder discussions on rate design have focused on addressing such issues within a rate case or utility pilots, but cautions that certain grid-mod investments must be paired with appropriated rates/tariffs to allow for the realization of complete value to customers and the grid. CENH further clarifies that in some cases appropriate pricing signals conveyed to customers can be a more cost-effective approach to create a customer initiated response which will result in a desired grid-mod outcome, and warns that utilities should not use the "rate design belongs only in rate cases" mantra as a justification for making grid mod investments without pairing them with appropriate rates.

[5] In its comments, CLF concurs with CENH that while conversations thus far have focused on addressing rate design issues within a rate case or utility pilots, certain grid mod investments must be paired with rate designs/tariffs to allow for the realization of complete value to customers and the grid. CLF similarly concurs that in some cases appropriate pricing signals conveyed to customers can be a more cost-effective approach to create a customer initiated response which will result in a desired grid-mod outcome, and warns that utilities should not use the "rate design belongs only in rate cases" mantra as a justification for making grid mod investments without pairing them with appropriate rates.

[6] In its comments, DES acknowledges that the IDP may not be the appropriate vehicle for setting strategic electrification (SE) policy, but suggests that the utilities should go beyond simply predicting the incremental level of electrification and planning for that growth in their IDPs, expressing a preference for IDPs that actively plan to enable SE, rather than passively forecast and plan for existing growth. It suggests numerous NH statutes that explicitly describe desired energy and environmental outcomes the IDPs should consider, citing a policy matrix compiled for the Benefit/Cost Working Group's recent Cost-Effectiveness Test Review. It further suggests that the benefits of strategic electrification are increasingly in line with the broad and specific policy outcomes in these statutes, which include lower overall costs, lower rates, a cleaner environment, reduced emissions, and improved public health. Its comments continue that IDPs could, if not should, include utility changes that enable faster integration of strategic electrification technologies (e.g., electric vehicles, air source heat pumps), and suggest these changes may need to be on the utility side to mitigate potential growth in consumption and load, whether through rate design or other means, noting utilities in their recent comments suggest that rates should only be addressed in rate cases.

9. Consumer Advisory/Stakeholder Engagement

The Stakeholders agreed that utilities should allow Stakeholder input before commencing the IDP process, and also once the utility has an initial IDP proposal, before filing it with the Commission. The Stakeholders also agreed that Stakeholders could participate in the IDP docket as part of the adjudicatory process. The Stakeholders agreed that basic access to data would be helpful (see above) prior to IDP filing and Stakeholder engagement. The Stakeholders did not agree on the specifics of how any input provided would be incorporated into the IDP.

11. LCIRP/IDP Integration

The Stakeholders agreed that the LCIRP should be combined with the IDP, but disagreed on whether the filing frequency should be every 3 years or every 5 years.[7]

<u>Open Issues</u>

1. Cost Effectiveness Methodology
2. Utility Cost Recovery[8, 9]
8. Consolidated Billing/General Billing
10. Capital Budgeting Process

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[7] In its comments, DES expresses uncertainty regarding whether it is necessary to amend RSA 378:38-39 to allow IDPs.

[8] In its comments, DES suggests the topic of cost recovery has been consistently overlooked or possibly avoided since the 2016-2017 Grid Mod Working Group process. Describing a position previously expressed during a fall technical session and in a follow-up clarification letter, DES notes an interest in opportunities to modify the utility business model/cost recovery such that "throughput incentive" or the "infrastructure bias" is minimized and distributed generation, demand response, and energy efficiency investments are given greater value. DES further suggests there may be opportunities to modify the existing regulatory models to achieve the same result and recommends a more complete discussion of opportunities to better align utility interests with overall rate reductions and improved environmental benefits, which it believes may impact the overall capital budgeting process.

[9] In its comments, CENH suggests the topic of utility cost recovery should also include the broader topic of utility business models and examine whether performance based regulation should be used in the context of grid mod.

Recommendations for Resolution of Issues

Following the two technical sessions, the parties could not reach agreement on an appropriate process going forward. The Non-Utility Stakeholders continue to request an adjudicative process leading to a Commission order, but do not have suggestions for the time-line or specific process needed.[10, 11] The Utilities do not believe an adjudication is needed, but continue to stress the need for resolution of outstanding issues before the utilities begin preparation of their respective IDPs. All Stakeholders expressed an interest in moving forward to resolve the outstanding issues as quickly as possible.

As a result, Staff recommends that the Commission consider the written comments filed in this investigation and issue an order resolving issues and providing additional process as the Commission deems appropriate.

[10] In its comments, DES expresses neutrality on what process is appropriate moving forward, and suggests concerns regarding how an adjudicative proceeding would work given that key issues such as utility cost recovery/utility business model and rate design remain completely untouched or have been pushed to other dockets.

[11] In its comments, CLF clarifies that an adjudicative proceeding may not be necessary on every single issue, but rather is seeking direction from the Commission with principles, objectives, and goals clearly identified so that the parties can focus their work and move forward toward grid modernization. It further suggests that workshops and working groups may be a good fit for many of the issues in this proceeding, but what is lacking is a charge for this group, with milestones, suggesting review of CLF's several sets of comments in this proceeding for more details.

BASELINE DISTRIBUTION SYSTEM, FINANCIAL, AND DER DEPLOYMENT DATA:

System Data

1. Updated values for Appendix B[1] to the Grid Modernization Working group report.[2]
2. Modeling and power flow software currently used (name and vintage)
    a. Is software capable of probabilistic or Monte Carlo method forecasting?
    b. Is there system interoperability or links between modeling software and other existing data platforms (e.g. Meter Data Management System (MDMS), Supervisory Control and Data Acquisition (SCADA), PI (Historian type database), Geographic Information System (GIS), Esri, etc.?
    c. Are there planned software deployments that will impact 2(a) and (b)?
    d. GIS system information, including how up to date the system is, the method and frequency for updating the data, how the data is used in planning, the methodology for validating the data, and operations models utilizing that data hosting capacity analysis.
    e. Annual peak load growth at the most granular level available i.e. the circuit, substation, town, operating area, or system level for each of the past five years and forecasted load growth for each of the next five years
3. Distribution system load forecast for all circuits, including circuit capacity, Including historic loading, both maximum peak day and minimum day, for the past three years, including projected new loading, and projected Distributed Energy Resource ("DER") impacts.
4. Number of substations (transmission to distribution or sub-transmission to distribution) which feed only distribution level customers.
    a. Percentage that have no remote monitoring at the feeder level.
    b. Percentage that have more detailed remote monitoring but no control.
    c. Percentage that have detailed remote monitoring and control.
    d. Any planned additions to enhance 3 (a) and (b).
5. Number of distribution substations (transmission to sub-transmission supply) whose circuits feed only the high side of another distribution substation.
    a. Percentage that have no remote monitoring at the sub-transmission feeder level.
    b. Percentage that have more detailed remote monitoring but no control.
    c. Percentage that have detailed remote monitoring and control.
    d. Any planned additions to enhance 4 (a) and (b).

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[1] http://puc.nh.gov/Regulatory/Docketbk/2015/15-296/LETTERS-MEMOS-TARIFFS/15-296_2017-03-20_NH_GRID_MOD_GRP_APP_FINAL_RPT.PDF

[2] http://puc.nh.gov/Regulatory/Docketbk/2015/15-296/LETTERS-MEMOS-TARIFFS/15-296_2017-03-20_NH_GRID_MOD_GRP_FINAL_RPT.PDF

6. Number of hybrid distribution substations (transmission to sub-transmission and distribution circuits) which may feed both distribution customers and provide sub-transmission to other distribution substations.
    a. Percentage that have no monitoring at the feeder/sub-transmission level.
    b. Percentage that have more detailed and complex monitoring but no control.
    c. Percentage that have detailed monitoring and control
    d. Are there planned additions to enhance 5 (a) and (b)
7. Sub-Feeder level visibility and measurement
    a. Distribution Feeder Level: Percentage that have 2 or more remote sensor monitoring on three phase mainline. Indicate type of measurement (voltage, current, etc.) and interval timeframe of data capture.
    b. Sub-transmission Feeder Level: Percentage that have 2 or more remote sensor monitoring on three phase mainline. Indicate type of measurement and interval timeframe of data capture.
    c. Summary of past (last 3 years) and future (next 3 years) annual installments of sensor devices at the sub-feeder level.
8. Number of customer meters with Advanced Metering Infrastructure ("AMI")/Advanced Meter Reading ("AMR")/Bridge AMR and those without, planned AMI/AMR/Bridge AMR or collector investments, and overview of existing functionality available.
9. Discussion of how the distribution system planning is coordinated with the integrated resource plan ("IRP") (including how it informs and is informed by the IRP), and planned modifications or planned changes to the existing process to improve coordination and integration between the two plans.
10. Discussion of how DER and at what level is considered in load forecasting (distribution feeder , sub-transmission level, distribution substation, bulk distribution substation level, or system-wide) and any expected changes in load forecasting methodology.
11. Discussion if and how the Institute of Electrical and Electronics Engineers (IEEE) Std. 1547-2018 impacts distribution system planning considerations (e.g. opportunities and constraints related to interoperability).
12. Distribution system annual loss percentage for the prior year.
13. The maximum hourly coincident monthly load, in kilo-volt-ampere (kVA), for the distribution system, in the past 12 months, as measured at the interface between the transmission and distribution system. This may be calculated using SCADA data or interval metered data or other non-billing metering / monitoring systems.
14. Total distribution/sub-transmission substation transformer nameplate in kVA.
15. Total distribution/sub-transmission line transformer nameplate in kVA (do not include capacity stated in Item 13)

16. Percentage of distribution substation transformers (which feed only distribution level customers) that are:
    a. 90-100% within their normal rating
    b. 80-90% within their normal rating
    c. Less than 80% of their normal rating
17. Percentage of sub-transmission substation transformers (whose circuits feed only the high side of another distribution substation) that are:
    a. 90-100% within their normal rating
    b. 80-90% within their normal rating
    c. Less than 80% of their normal rating
18. Percentage of distribution feeders that are:
    a. 90-100% within their normal rating
    b. 80-90% within their normal rating
    c. Less than 80% of their normal rating
19. Percentage of sub-transmission feeders that are:
    a. 90-100% within their normal rating
    b. 80-90% within their normal rating
    c. Less than 80% of their normal rating
20. Total miles of overhead distribution wire:
    a. Three phase
    b. Single phase or two phase
21. Total miles of underground distribution wire
    a. Three phase
    b. Single phase or two phase
22. Total number of distribution customers
    a. Distribution Feeder customers
    b. Primary meter customers
23. Utility-wide System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), Customer Average Interruption Duration Index (CAIDI), Customers Interrupted per Interruption (CIII) (IEEE) for the past three years.
24. Ranking of circuits by contribution to SAIDI and SAIFI (IEEE) for the past three years.
25. Information regarding any existing Conservation Voltage applications. (e.g. used to limit only peak loading, or for continuous management of voltage levels across the application area)
26. Number of separately metered electric vehicle charging systems added to the Company's distribution system over each of the past three years.
27. Number of electric vehicle charging systems currently forecasted to be installed in the next three to five years.

Financial Data

1. Historical distribution system spending for the past 5-years, in each category:
    a. Age-Related Replacements and Asset Renewal
    b. System Expansion or Upgrades for Capacity
    c. System Expansion or Upgrades for Reliability and Power Quality
    d. New Customer Projects and New Revenue
    e. Grid Modernization and Pilot Projects
    f. Government Mandates
    g. Metering
    h. Other
2. Projected distribution system spending for 5-years into the future for the categories listed above, itemizing any non-traditional distribution projects.
3. Planned distribution capital projects, including drivers for the project (e.g. see list in Financial Data #1), timeline for improvement, summary of anticipated changes in historic spending.
4. Provide any available cost benefit analysis in which the company evaluated a non-traditional distribution system solution to either a capital or operating upgrade or replacement.

DER Deployment

1. Current distributed generation deployment by type (photovoltaic, hydro, wind, etc.), size (≤100 kilowatt ("kW"), 100kW-1 megawatt ("MW"), >1MW), and geographic dispersion (as useful for planning purposes; such as, by planning areas, service/work center areas, cities, etc.)
2. Information on areas of existing or forecasted high distributed generation penetration. Include definition and rationale for what the Company considers "high" penetration. Include number and location of known sub-stations and circuits with no or very limited hosting capacity (e.g. for systems 500kW or greater) without significant distributed generation developer investment, and the cause of the limitation.
3. Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology; provide information describing experiences where distributed generation installations have caused operational challenges such as power quality, voltage or system overload issues, and associated customer complaints.
4. Information regarding any existing plans the Company has to develop a hosting capacity analysis.

5. Total number of applications and cost spent on distributed generation installation in the prior year (including application review, responding to inquiries, metering, testing, make ready, etc).
6. Total charges to customers/member installers for DER generation installations, in the prior year (including application, fees, metering, make ready, etc.).
7. Total nameplate kW of distributed generation system which completed interconnection to the system in the prior year.
8. Total number of distributed generation systems which completed interconnection to the system in the prior year.
9. Average interconnection time, and range of review time, per application type (≤100kW, 100kW-1MW, >1MW) as well as number of still pending applications and specific number, if any, of applications still spending after 6 months.
10. The data sources and methodology used to complete the initial review screens outlined in the Company's DER Interconnection Process.
11. Information regarding any existing plans to develop an online interconnection platform showing the queue, a project’s place in line, and other relevant information
12. Information regarding any existing plans to require all new DER installations to comply with IEEE 1547-2018.
13. Information regarding any existing plans to utilize reactive power functions defined within IEEE Std 1547TM-2018, including constant power factor mode, voltage-reactive power mode (a.k.a. volt-var), active power-reactive power mode (a.k.a. watt-var), constant reactive power mode, and/or the voltage-active power mode (a.k.a. volt-watt)
14. Information regarding any existing plans to allow intentional islanding or micro-grids.

Clean Energy NH

DRAFT FOR DISCUSSION

STATE OF NEW HAMPSHIRE

Inter-Department Communication

DATE: October 16, 2019
AT (OFFICE): NHPUC

FROM: Leszek Stachow
Anne Ross
Liz Nixon
Kurt Demmer
Brian Buckley

SUBJECT: IR 15-296 Staff Report on Technical Sessions
Order No. 26,254 (May 29, 2019)

TO: Commissioner Bailey
Commissioner Giaimo
Debra Howland, Executive Director

Comments and Technical Sessions

Following written comments filed on September 6, 2019, representatives of the following stakeholders met in two technical sessions, held at the Commission on September 19, and October 10, 2019.

Eversource Energy
Unitil Energy Service
Liberty Utilities
Clean Energy NH
Conservation Law Foundation (CLF)
NH Department of Environmental Services
City of Lebanon
Office of Consumer Advocate (OCA)
Direct Energy
Pat Martin

The two technical sessions on September 19, and October 10, 2019, were facilitated by David Littell, senior advisor for the Regulatory Assistance Project. Mr. Littell focused

CENH

discussion at the technical sessions on the 11 topics identified in Order No. 26,254 (May 29, 2019).

1. Cost Effectiveness Methodology
2. Utility Cost Recovery
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8. Consolidated Billing/General Billing
9. Consumer Advisory Council/Stakeholder Engagement
10. Capital Budgeting Process
11. LCIRP/IDP Integration

In addition, the Wired Group (OCA's expert) presented its recommended analytical approach to evaluating projects within the distribution system investment planning process to Stakeholders on October 9, 2019.

<u>Issues Where Limited Consensus is Possible.</u>

The OCA took the position that it could not agree to any aspects of the 11 issues. Instead, OCA wants to present the analytic approach of its expert to the Commission and reserved its right to litigate all issues surrounding grid modernization. Throughout the rest of this memo, when Stakeholders are mentioned, OCA is not included in the reference. Nonetheless, based on discussions among Stakeholders at the two technical sessions, other stakeholders appeared to agree on some aspects of these issues and proposed that a list of areas where agreement might be reached be circulated for consideration. Staff has circulated this memo to identify those issues for consideration.

3. Utility and Customer Data and Third Party Access

Stakeholders agreed that customer data would be dealt with in a separate Commission docket pursuant to SB 284 (2019).

Stakeholders agreed that baseline data is needed for each utility distribution system prior to filing of the IDPs to help inform stakeholder input for utility preparation of the IDPs, and that data should be provided on an individual circuit level, though some utilities noted they may not have baseline data for every individual circuit yet.

Staff has suggested elements of the required baseline data which are attached to this memorandum and were circulated to the stakeholders for preparation of comments attached to this filing.

4. Hosting Capacity/Locational Value Analysis/Interconnection

CENH

Stakeholders agreed that a standing working group should be created before utility Integrated Distribution Plans were filed and should remain in place in order to receive data and information on each utility's progress on hosting capacity analysis and presentation, locational valuation initiatives, and interconnection procedures.

Commented [A1]: In our view the role of such a working group or standing technical committee would involved much more than merely passively receiving information. We envision a truly collaborative process between utilities and DER developers to improve existing interconnection procedures and plan ahead to avoid future interconnection limitations and delays, in addition to making available detailed hosting capacity information.

The goals of such a working group would also be to create consistency between the three utilities interconnection application, review, and queue process with a goal to increase information sharing between developers and utilities to reduce work burden and any potential interconnection delays. This working group would also be an appropriate venue to develop tiered interconnection queues and develop an approach to shared cost approach to multiple DER projects proposing to connect in close proximity.

Stakeholders noted that the separate locational value study taking place in Docket No. DE 16-576 also focusses on locational valuation. The IDP planning process and data prepared for that process may benefit from this study and there may be synergies between the study and stakeholder engagement process already underway in DE 16-576 and the tasks of this IDP working group envisioned to address hosting capacity, locational value, and interconnection issues in IR 15-296. We expect stakeholders will comment on these potential synergies in the attached comments and perhaps in DE 16-576 as well.

5. Annual Reporting Requirements

Stakeholders agreed that annual reports on the utility distribution systems would be appropriate. The specific data that will be included in these reports remains open.

6. Rate Design Policy

Stakeholders agreed that rate design should be addressed as part of a rate case, and supported utility pilots on new rate design approaches as a way to test the effectiveness of new rate designs that could be adopted in a rate case.

Commented [A2]: Though this generally describes stakeholder discussions around this issue, CENH feels strongly that certain grid-mod investments must be paired with appropriated rates/tariffs to allow for the realization of complete value to customers and the grid. In addition, in some cases appropriate pricing signals conveyed to customers can be a more cost effective approach to create a customer initiated response which will result in a desired grid-mod outcome.

Therefore, utilities should not use the "rate design belongs only in rate cases" excuse to make grid mod investments without pairing them with appropriate rates but rather plan accordingly.

7. Strategic Electrification Policy

Stakeholders agreed that the Commission's IDP process is not a vehicle for setting policy on strategic electrification, but agreed that each utility should, in its load and peak forecasts, predict the level of incremental electrification in its service territory as part of its IDP. Further SB 575(2018) requires the Commission to consider rate design standards for electric companies, including time of day rates for charging electric vehicles for both residential and commercial customers, as well as interruptible rates, demand charges, load management and seasonal rates.

9. Consumer Advisory/Stakeholder Engagement

The Stakeholders agreed that utilities should allow stakeholder input before commencing the IDP process, and also once the utility has an initial IDP proposal, before filing it with the Commission. The Stakeholders also agreed that stakeholders could participate in the IDP docket as part of the adjudicatory process. The Stakeholders agreed that basic access to data would be helpful (see above) prior to IDP filing and stakeholder engagement. The stakeholders did not agree on the specifics of how any input provided would be incorporated into the IDP.

11. LCIRP/ IDP Integration

The Stakeholders agreed that the LCIRP should be combined with the IDP, but disagreed on whether the frequency should be every 3 years or every 5 years.

C_ENH

Open Issues

1. Cost Effectiveness Methodology
2. Utility Cost Recovery

8. Consolidated Billing/General Billing

10. Capital Budgeting Process

Commented [A3]: In our view, and likely other stakeholders, this also should include the broader topic of utility business models including if performance based regulation should be used in the context of grid mod.

Recommendations for Resolution of Issues

Following the two technical sessions the parties could not reach agreement on an appropriate process going forward. The Non-Utility Stakeholders continue to request an adjudicative process leading to a Commission order, but do not have suggestions for the time-line or specific process needed. The Utilities do not believe an adjudication is needed, but continue to stress the need for resolution of outstanding issues before the utilities begin preparation of their respective IDPs. All Stakeholders expressed an interest in moving forward to resolve the outstanding issues as quickly as possible.

As a result, Staff recommends that the Commission consider the written comments filed in this investigation and issue an order resolving issues and providing additional process as the Commission deems appropriate.

CLF

DRAFT FOR DISCUSSION

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The OCA has indicated that it will be filing comments separately. Throughout the rest of this memo, when Stakeholders are mentioned, OCA is not included in the reference. Nonetheless, based on discussions among Stakeholders at the two technical sessions, other stakeholders appeared to agree on some aspects of these issues and proposed that a list of areas where agreement might be reached be circulated for consideration. Staff has circulated this memo to identify those issues for consideration.

3. Utility and Customer Data and Third Party Access

Stakeholders agreed that customer data would be dealt with in a separate Commission docket pursuant to SB 284 (2019).

Commented [A1]: While there will be a separate docket on customer data, we think that it would be good to acknowledge that keeping that work connected to grid mod efforts will be important.

Stakeholders agreed that baseline data is needed for each utility distribution system prior to filing of the IDPs to help inform stakeholder input for utility preparation of the IDPs, and that data should be provided on an individual circuit level, though some utilities noted they may not have baseline data for every individual circuit yet.

Staff has suggested elements of the required baseline data which are attached to this memorandum and were circulated to the stakeholders for preparation of comments attached to this filing.

Commented [A2]: See CLF's comments in our cover email.

4. Hosting Capacity/Locational Value Analysis/Interconnection

Stakeholders agreed that a standing working group should be created before utility Integrated Distribution Plans were filed and should remain in place in order to receive

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data and information on each utility's progress on hosting capacity analysis and presentation, locational valuation initiatives, and interconnection procedures.

Stakeholders noted that the separate locational value study taking place in Docket No. DE 16-576 also focusses on locational valuation. The IDP planning process and data prepared for that process may benefit from this study and there may be synergies between the study and stakeholder engagement process already underway in DE 16-576 and the tasks of this IDP working group envisioned to address hosting capacity, locational value, and interconnection issues in IR 15-296. We expect stakeholders will comment on these potential synergies in the attached comments and perhaps in DE 16-576 as well.

Commented [A3]: CLF believes that this a working group must do more than just receive information from the utilities. We support a collaborative process that includes a broad range of stakeholders aimed at improving interconnection procedures and planning to avoid limitations and delays in deploying DER, in addition to access to detailed hosting capacity information. This working group could increase consistency among the utilities interconnection application, review, and queue management processes and increase information sharing between developers and utilities.

5. Annual Reporting Requirements

Stakeholders agreed that annual reports on the utility distribution systems would be appropriate. The specific data that will be included in these reports remains open.

6. Rate Design Policy

Commented [A4]: CLF agrees with CENH that while this generally captures the conversations thus far, certain grid mod investments must be paired with rate designs/tariffs to allow for the realization of complete value to customers and the grid. In addition, in some cases appropriate pricing signals conveyed to customers can be a more cost effective approach to create a customer initiated response which will result in a desired grid-mod outcome. Therefore, the idea that "rate design belongs only in rate cases" should not be used as an excuse to make grid mod investments that require different approaches to rate design.

Stakeholders agreed that rate design should be addressed as part of a rate case, and supported utility pilots on new rate design approaches as a way to test the effectiveness of new rate designs that could be adopted in a rate case.

7. Strategic Electrification Policy

Stakeholders agreed that the Commission's IDP process is not a vehicle for setting policy on strategic electrification, but agreed that each utility should, in its load and peak forecasts, predict the level of incremental electrification in its service territory as part of its IDP. Further SB 575(2018) requires the Commission to consider rate design standards for electric companies, including time of day rates for charging electric vehicles for both residential and commercial customers, as well as interruptible rates, demand charges, load management and seasonal rates.

9. Consumer Advisory/Stakeholder Engagement

The Stakeholders agreed that utilities should allow stakeholder input before commencing the IDP process, and also once the utility has an initial IDP proposal, before filing it with the Commission. The Stakeholders also agreed that stakeholders could participate in the IDP docket as part of the adjudicatory process. The Stakeholders agreed that basic access to data would be helpful (see above) prior to IDP filing and stakeholder engagement. The stakeholders did not agree on the specifics of how any input provided would be incorporated into the IDP.

11. LCIRP/ IDP Integration

The Stakeholders agreed that the LCIRP should be combined with the IDP, but disagreed on whether the frequency should be every 3 years or every 5 years.

Open Issues

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1. Cost Effectiveness Methodology

2. Utility Cost Recovery

8. Consolidated Billing/General Billing

10. Capital Budgeting Process

Recommendations for Resolution of Issues

Following the two technical sessions the parties could not reach agreement on an appropriate process going forward. The Non-Utility Stakeholders continue to request an adjudicative process leading to a Commission order, but do not have suggestions for the time-line or specific process needed. The Utilities do not believe an adjudication is needed, but continue to stress the need for resolution of outstanding issues before the utilities begin preparation of their respective IDPs. All Stakeholders expressed an interest in moving forward to resolve the outstanding issues as quickly as possible.

As a result, Staff recommends that the Commission consider the written comments filed in this investigation and issue an order resolving issues and providing additional process as the Commission deems appropriate.

Commented [A5]: CLF is not necessarily saying that an adjudicative proceeding is necessary on every single issue; we are seeking direction from the Commission with principles, objectives, and goals clearly identified so that at the parties can focus their work and move forward toward grid mod. Workshops and working groups are probably a good fit for many of the issues in this proceeding, but what is lacking is a charge for this group, with milestones. Please see CLF's several sets on comments in this proceeding for more details.

NH DES

DRAFT FOR DISCUSSION

STATE OF NEW HAMPSHIRE

Inter-Department Communication

DATE: October 16, 2019
AT (OFFICE): NHPUC

FROM: Leszek Stachow
Anne Ross
Liz Nixon
Kurt Demmer
Brian Buckley

SUBJECT: IR 15-296 Staff Report on Technical Sessions
Order No. 26,254 (May 29, 2019)

TO: Commissioner Bailey
Commissioner Giaimo
Debra Howland, Executive Director

Comments and Technical Sessions

Following written comments filed on September 6, 2019, representatives of the following stakeholders met in two technical sessions, held at the Commission on September 19, and October 10, 2019.

Eversource Energy
Unitil Energy Service
Liberty Utilities
Clean Energy NH
Conservation Law Foundation (CLF)
NH Department of Environmental Services
City of Lebanon
Office of Consumer Advocate (OCA)
Direct Energy
Pat Martin

The two technical sessions on September 19, and October 10, 2019, were facilitated by David Littell, senior advisor for the Regulatory Assistance Project. Mr. Littell focused

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discussion at the technical sessions on the 11 topics identified in Order No. 26,254 (May 29, 2019).

1. Cost Effectiveness Methodology
2. Utility Cost Recovery
3. Utility and Customer Data and Third Party Access
4. Hosting Capacity/Locational Value Analysis/Interconnection
5. Annual Reporting Requirements
6. Rate Design Policy
7. Strategic Electrification Policy
8. Consolidated Billing/General Billing
9. Consumer Advisory Council/Stakeholder Engagement
10. Capital Budgeting Process
11. LCIRP/IDP Integration

In addition, the Wired Group (OCA's expert) presented its recommended analytical approach to evaluating projects within the distribution system investment planning process to Stakeholders on October 9, 2019.

Issues Where Limited Consensus is Possible.

The OCA took the position that it could not agree to any aspects of the 11 issues. Instead, OCA wants to present the analytic approach of its expert to the Commission and reserved its right to litigate all issues surrounding grid modernization. Throughout the rest of this memo, when Stakeholders are mentioned, OCA is not included in the reference. Nonetheless, based on discussions among Stakeholders at the two technical sessions, other stakeholders appeared to agree on some aspects of these issues and proposed that a list of areas where agreement might be reached be circulated for consideration. Staff has circulated this memo to identify those issues for consideration.

3. Utility and Customer Data and Third Party Access

Stakeholders agreed that customer data would be dealt with in a separate Commission docket pursuant to SB 284 (2019).

Stakeholders agreed that baseline data is needed for each utility distribution system prior to filing of the IDPs to help inform stakeholder input for utility preparation of the IDPs, and that data should be provided on an individual circuit level, though some utilities noted they may not have baseline data for every individual circuit yet.

Staff has suggested elements of the required baseline data which are attached to this memorandum and were circulated to the stakeholders for preparation of comments attached to this filing.

4. Hosting Capacity/Locational Value Analysis/Interconnection

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Stakeholders agreed that a standing working group should be created before utility Integrated Distribution Plans were filed and should remain in place in order to receive data and information on each utility's progress on hosting capacity analysis and presentation, locational valuation initiatives, and interconnection procedures.

Stakeholders noted that the separate locational value study taking place in Docket No. DE 16-576 also focusses on locational valuation. The IDP planning process and data prepared for that process may benefit from this study and there may be synergies between the study and stakeholder engagement process already underway in DE 16-576 and the tasks of this IDP working group envisioned to address hosting capacity, locational value, and interconnection issues in IR 15-296. We expect stakeholders will comment on these potential synergies in the attached comments and perhaps in DE 16-576 as well.

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Stakeholders agreed that the Commission's IDP process is not a vehicle for setting policy on strategic electrification, but agreed that each utility should, in its load and peak forecasts, predict the level of incremental electrification in its service territory as part of its IDP. Further SB 575(2018) requires the Commission to consider rate design standards for electric companies, including time of day rates for charging electric vehicles for both residential and commercial customers, as well as interruptible rates, demand charges, load management and seasonal rates.

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11. LCIRP/ IDP Integration

The Stakeholders agreed that the LCIRP should be combined with the IDP, but disagreed on whether the frequency should be every 3 years or every 5 years.

Commented [A1]: While the IDP may not be the appropriate vehicle for setting strategic electrification (SE) policy, it seems that the IDPs should go beyond simply predicting the incremental level of electrification and planning for that growth in its IDP. The above is a passive process, whereas the IDPs could actively plan to enable SE.

There are numerous NH statutes that explicitly describe the desired energy and environmental outcomes (see EERS B/C working group policy matrix compiled by Erin Malone, Synapse). The benefits of strategic electrification are increasingly in line with the broad and specific policy outcomes in these statutes, which include lower overall costs, lower rates, a cleaner environment, reduced emissions, improved public health, etc.

It seems that IDPs could, if not should, include utility changes that ENABLE faster integration of strategic electrification technologies (e.g., EVs, ASHPs). These changes may need to be on the utility side to mitigate potential growth in consumption and load, whether through rate design or other.

This comment then ties to #6 as the utilities in their proposal noted that rates should only be addressed in rate cases.

Commented [A2]: Does there need to be a statement about the current adequacy of RSA 378:38-39 to allow IDPs or whether the statute needs to be amended?

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Open Issues

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Recommendations for Resolution of Issues

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As a result, Staff recommends that the Commission consider the written comments filed in this investigation and issue an order resolving issues and providing additional process as the Commission deems appropriate.

Commented [A3]: This has been a topic that has been consistently overlooked or possibly avoided since the 2016-2017 Grid Mod Working Group process.

As NHDES noted during one technical session during the fall and in a follow-up clarification letter, the department is interested in a conversation regarding opportunities of modify the utility business model/cost recovery such that "throughput incentive" or the "infrastructure bias" is minimized and DG, DR, and EE investments are given greater value. There may also be opportunities to modify the existing regulatory models to achieve the same result. In either case, NHDES would like to see a more complete discussion of opportunities to better align utility interests with overall rate reductions and improved environmental benefits.

The outcome of this conversation may have impacts on #10.

Commented [A4]: NHDES is neutral on this issue as it is unclear on how an adjudicative proceeding would work given that key issues such as utility cost recovery/utility business model and rate design remain completely untouched or have been pushed to other dockets.