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October 23, 2020

Debra A. Howland
Executive Director
New Hampshire Public Utilities Commission
21 S. Fruit Street, Suite 10
Concord, NH 03301

Re: Docket No. DE 19-197
Development of a Statewide Multi-Use Online Energy Data Platform
Staff Testimony

Dear Ms. Howland:

Enclosed for filing in the above captioned proceeding is the Pre-filed Joint Testimony of Utility Analysts Stephen R. Eckberg and Jason Morse. Pursuant to the Secretarial Letter issued on March 17, 2020 this testimony is being submitted electronically and hard copies will not follow unless requested. Staff certifies that copies of the testimony and attachments have been served electronically to the parties on the service list upon filing with the Commission.

Thank you for your attention to this matter.

Sincerely,

Brian D. Buckley

Brian D. Buckley
Staff Attorney

cc: Docket Service List
Attachments

Docket #: 19-197 **SERVICE LIST - DOCKET RELATED - Email Addresses** Printed : 10/23/2020

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STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DOCKET DE 19-197

IN THE MATTER OF: Electric and Natural Gas Utilities
Development of a Statewide, Multi-Use
Online Energy Data Platform

JOINT REBUTTAL TESTIMONY

OF

Stephen R. Eckberg
Utility Analyst, Electric Division

And

Jason Morse
Utility Analyst, Sustainable Energy Division

October 23, 2020

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I. INTRODUCTION

Q. Please state your full names.

A. Stephen R. Eckberg.

A. Jason Morse.

Q. By whom are you employed and what is your business address?

A. [Eckberg] I am employed as a utility analyst with the Electric Division of the New Hampshire Public Utilities Commission. My business address is 21 South Fruit Street, Suite 10, Concord, NH, 03301.

A. [Morse] I am employed as a utility analyst with the Sustainable Energy Division of the New Hampshire Public Utilities Commission. My business address is 21 South Fruit Street, Suite 10, Concord, NH, 03301.

Q. Please summarize your relevant education and professional work experiences.

A. [Eckberg and Morse] Our education and work experience are provided in our joint direct testimony in this docket and we will not repeat it here.

Q. What is the purpose of your joint testimony?

A. The purpose of our testimony is to advise the Commission regarding some of the non-consensus issues in this docket, to highlight other relevant issues, and to expand upon the recommendation presented in our direct pre-filed testimony regarding how the Commission might determine whether the costs of any proposed statewide, multi-use online energy data platform are reasonable and in the public interest using a two-phase approach.

Q. How is your testimony organized?

A. Section I introduces and summarizes our testimony. Section II discusses the potential costs of the platform. Section III discusses platform cost recovery. Section IV discusses platform governance. Section V discusses platform architecture. Section VI provides a summary and conclusions.

Q. Are you providing testimony regarding all of the issues that will need to be addressed in DE 19-197?

A. No. The scope of our rebuttal testimony will focus primarily on advising the Commission regarding only certain key issues which are non-consensus among the parties.[1]

Q. What issues have you identified as non-consensus issues among the parties at this time?

A. There appears to be disagreement among parties' positions in pre-filed testimony regarding multiple issues important to the development and implementation of the project.[2] We will provide more detail on only *some* of those issues below.

II. PLATFORM COSTS

Q. Is there relevant information from other utilities or jurisdictions that can help the Commission better understand the potential costs of the platform?

A. Yes. Dunsky Energy Consulting prepared a 2017 report analyzing the costs and benefits of Green Button Connect (GBC) implementation for 72 electric and three natural gas utilities in Ontario, Canada.[3] (Ontario Report) This analysis, while described as "high-level" by its

[1] Our rebuttal testimony should be understood as supplementing, rather than supplanting, our initial testimony.

[2] These include, but are not limited to: (1) Recovery of the data platform's development and operational costs; (2) the data platform's system architecture; (3) Governance of the data platform; (4) Manner of implementing the platform (Design Pilot, Timing of an RFP relative to designing the platform and its components, hiring of an independent project leader or designation of the Utilities as project leaders); (5) Whether the utilities primarily build the platform, should a third party, or should it be a combination of these; (6) Security and data access issues including but limited to: anonymization protocols; data encryption; data retention policies; and data sharing with third-parties; and (7) the platform data requirements and/or use cases that it should support.

[3] Attachment Rebuttal SRE-JM-1. Dunsky Energy Consulting. Green Button Cost-Benefit Analysis Report. October 2017. Available also at: https://www.ontarioenergyreport.ca/pdfs/Green%20Button%20Cost-Benefit%20Analysis%20Report%20FINAL.PDF (The report also considers Ontario's 515 water utilities, but we do not reference that portion of the report as it is not applicable to the NH statewide energy data platform.).

author, appears to be the most robust available analysis of the costs of GBC functionality. We note that this analysis considers separate GBC implementations for each utility, and that this is not an analysis of a platform in which multiple utilities share a logical data model and/or potentially share a common endpoint as has been proposed by some parties in this docket. The Ontario Report also reviews implementations in Canada, which might limit its relevancy to the New Hampshire platform. We also note that as a three year old analysis, it might already be considered somewhat outdated. We therefore do not advise drawing cost estimates for a NH platform directly from the Ontario Report's analysis, rather, we reference this analysis within our testimony because it may provide some relevant insights for New Hampshire to consider.

Q. Please describe some of the categories of costs that might be incurred for deployment of a data platform.

A. The Ontario Report separately categorizes the costs of a GBC implementation into three main categories: set-up, integration, and ongoing annual costs.

Set-up costs include all one-time costs required to develop the GBC functionality. The authors describe set-up costs as including front-end solutions, cloud services, the Green Button platform, development and testing of the services to manage third party applications, and testing of required security and privacy mechanisms and protocols. The Ontario Report suggests that these particular costs are highly dependent on what functionality is included, and are relatively fixed costs in the sense that they are not expected to vary much based on the size of a utility or the complexity of its systems. The Ontario Report estimates that set-up costs would amount to $50,000 per utility implementation.[4]

[4] The Ontario Report uses Canadian Dollars. To convert to United States dollars, one would multiply cost figures found in the report by approximately 0.75.

Integration costs are described as including all of the one-time costs incurred to integrate the platform with the utilities' data systems and processes. The Ontario Report suggests that these costs are expected to vary widely based on the size of a utility and the complexity of its data systems. These costs are described as primarily resulting from the extracting, transforming, and loading of data from the utilities' data storage systems into the platform.

Ongoing annual costs are described as including all of the costs required to maintain the platform, maintain and update the integrations, manage third party registration, and other costs that are likely to recur.

We also suggest that there is a fourth category of costs which might be considered, depending on the requirements of a statewide platform. These are **indirect costs**. We define indirect costs as any costs that are not incurred directly for the platform's set-up, integration, or ongoing annual requirements, but would be incurred as a result of a requirement of the data platform.

Q. Which category of costs is expected to be most significant for the NH Statewide Energy Data Platform?

A. Using the definitional framework above, the highest expected costs associated with implementing the New Hampshire platform appear to be the integration costs. Eversource and Unitil note this in their pre-filed testimony, and further suggest in response to discovery Staff 01-011(a) that this category of costs represents 85% of the costs and effort related to a platform implementation.[5]

The Ontario Report estimates that integration costs for a large utility of any type (defined as >150,000 customers) are $225,000, costs for a medium utility (defined as between 30,000

[5] Attachment Rebuttal SRE-JM-2. Eversource and Unitil Response STAFF 01-011.

and 150,000 customers) are $72,000, and costs for a small utility (defined as <30,000 customers) $22,500.[6] They estimate that these costs would increase by 33% if the utility were to implement the platform in-house as opposed to pursuing a Software-as-a-Service agreement.

If the assumption made in the Ontario Report that larger utilities will incur significantly higher costs for integration due to more complex internal data structures proves to be true for New Hampshire, we should expect that the potential cost of integrating Eversource's data into the platform will be one of the highest specific costs of platform implementation.

Q. Is there a risk that these integration costs would need to be re-incurred if a utility updates their back-end data storage systems in the future?

A. Yes. In particular, we suggest that the Commission consider the testimony and discovery responses of Liberty Utilities which state that the Company is currently planning to change its billing system from its current "Cogsdale" system to a new "SAP" system. Liberty's response to Staff 2-2 states "Considering Liberty is in the process of designing the new billing system, trying to adapt Cogsdale to feed in to the statewide platform would be a waste of time and money."[7] The Company has estimated that the new billing system will be ready to use during Q2 2022. It appears that if the Commission orders Liberty Utilities to begin a platform implementation before its new billing system is in place, the result might be that the Company and/or contractors would undertake efforts to design, map, extract, transform, and load/prepare data from Liberty's current data storage systems, but these efforts would

[6] The approximate customer-base of the NH Utilities are: Eversource Energy (electric): 560,000; Unitil Energy Systems, Inc. (electric): 100,000; Granite State Electric Corp. d/b/a Liberty Utilities (electric): 43,000 Northern Utilities, Inc. (gas): 27,000; Energy North Natural Gas Corp. d/b/a Liberty Utilities (gas): 87,000.

[7] Attachment Rebuttal SRE-JM-3. Liberty Response Staff 2-2(c).

become obsolete and need to be re-done within a very short timeframe. It therefore might be in the public interest to defer integration of Liberty's data into a statewide data platform until its new billing system and data sources are being used, in order to avoid incurring integration costs that would need to be re-incurred.

Q. Might additional integration costs be expected when new data elements are added into the platform?

A. Yes. To provide one example, Eversource states in response to Staff 1-011 (e) that "Implementing AMI in NH could result in a major [data platform] cost impacts. Either the source could be changed to pull data from the AMI MDMS (meter data management system) or additional data and a much greater volume of data would be available in the Azure data lake. An estimation of cost would have to be developed at that point."[8] Given that Eversource does not currently have a timeline for AMI implementation in NH, that such an implementation might be many years in the future, and that it is not clear to what extent the current back-end data storage systems would be replaced upon an AMI implementation, it does not appear to be possible to predict when this cost might need to be incurred or how large this particular cost might be. However, we bring this to the Commission's attention as an example of the potential future platform costs that could be above the "normal" expected operations & maintenance costs.

As another example, if it is determined that certain "System data" elements may be integrated into the platform at a later date, additional costs related to integrating that data should be expected. Eversource and Unitil state in response to Staff 01-011 (c) that "Cost would be affected by the number of source systems or tables required and the time period

[8] Supra at Note 5.

involved. For example, system data is generally not tied to billing data, which would result in higher integration costs."[9]

Q. Could a requirement of the data platform result in additional costs that might not be considered direct costs of the platform?

A. As mentioned above, the data platform could potentially create indirect costs. For example, if hourly load data is necessary to enable certain platform functionalities, and a utility's systems are only designed to collect monthly load data, updating that utility's systems could become an indirect cost related to satisfying the platform requirements.

Q. How might the Commission limit indirect costs?

A. To limit indirect costs, the Commission could clarify that any adopted data sharing requirements or use case should be limited by existing data collection frequency, granularity, and storage capabilities.[10] Under such an arrangement, if the data required to enable certain platform functionalities is not already available to a utility, the Commission would have the opportunity to understand any indirect costs that would need to be incurred as a result of adopting incremental platform functionalities or use cases.

Q. Can you further describe the potential costs of operating and maintaining the platform?

Yes, there are expected to be a number of ongoing costs for the operation and maintenance the platform. The Ontario Report estimates ongoing annual costs of between $0.80 and $1.20 per customer per year depending on the implementation type. A Statewide platform

[9] *Id*.

[10] One exception of this general rule would be if the Commission found costs associated with functionalities beyond the minimum viable platform to be reasonable and in the public interest, including designing the platform to be extensible to future additional data collection frequencies and granularities.

might have additional incremental ongoing costs beyond what would be incurred to operate and maintain separate GBC implementations. We recommend that RFI or RFP responses for the NH platform should separately estimate expected annual operation and maintenance costs, and clearly explain the extent to which those estimates account for possible future data integration/re-integration efforts. We also recommend that the responses provide separate annual ongoing cost estimates for a platform that uses the different architecture options, such as a central database, a virtual platform, an "API of APIs", and/or a centralized web portal. These architectural options are discussed in more detail in Section V of this testimony.

Q. What additional costs might be incurred beyond those already mentioned above?

Below we provide a list of some other potential costs that might be incurred as part of an initial and ongoing platform implementation. This list is not exhaustive and is based on the features and functionalities that have been proposed in parties' testimony. To the extent certain features/functionalities are not adopted as part of a platform, some of these costs might not apply.

- Any performance incentive, rate of return, or other utility incentive;
- Any tracking and reporting system and/or related functionality integrated into the platform;
- Any independent entity which might host, support, provide customer service for, or incur any other costs related to the data platform;
- Any identity management, token management etc. services included in the platform;
- Any physical data warehouse(s) involved in the platform architecture, whether hardware or cloud-based;

- Initial and ongoing costs related to a website or other location which provides centralized access and documentation related to the data platform, and any associated functions or features;
- The costs of any future updates, upgrades, additional functionalities, or data mapping exercises that would not be included in an initial version of the platform or its expected annual maintenance costs;
- All licensing and certification costs related to the platform;
- The costs of any consultant that might be needed; and
- Any additional costs related to the providing of aggregated/anonymized data, which might include anonymization/screening software and/or manual intervention by administrative staff.

Q. Please summarize your observations relating to potential platform costs.

A. We recommend the Commission consider the full universe of potential platform costs as it evaluates whether the costs of implementation are reasonable and in the public interest. These costs include set-up costs, integration costs, ongoing direct costs, and indirect costs. We recommend that RFI or RFP responses for the NH platform should separately estimate expected annual operation and maintenance costs, and clearly explain the extent to which those estimates account for possible future data integration/re-integration efforts. We also recommend that the responses provide separate annual ongoing cost estimates for a platform that uses the different architecture options, such as a central database, a virtual platform, an "API of APIs", and/or a centralized web portal.

III. PLATFORM COST RECOVERY

Q. If the Commission approves the development of an Online Energy Data Platform, how might costs incurred by the Utilities to develop and enable the platform be recovered?

A. RSA 378:54 provides that the utilities may: (1) "Impose reasonable charges to third parties for access to data via the multi-use, online energy data platform" and (2) "Otherwise recover costs from customers in a timely manner as approved by the commission."

There are several methods by which the Utilities might recover costs related to the data platform. One is recovery from ratepayers through distribution rates. Another is recovery from ratepayers through the Systems Benefit Charge (SBC) and Local Distribution Adjustment Charge (LDAC). Another might be charging a reasonable fee to third parties for the use of the platform.[11]

A. Platform Cost Recovery – Positions of the Parties

Q. Did any of the utilities who provided testimony in this proceeding offer input on the cost recovery issue?

A. Yes. The Joint Testimony of Eversource/Unitil witnesses addressed this is some detail. The witnesses stated that prior to inclusion of the energy data platform costs in distribution rates, they would propose that cost recovery be allowed as a separate stand-alone adder, as it would facilitate more timely recovery of costs. Absent such timely recovery, the Utilities stated a

[11] Beyond these three high-level cost-recovery mechanisms, there are additional details related to cost recovery that the Commission might address. These details are related to the timeliness in which the costs would be recovered, whether the Utilities should be given the opportunity to earn a rate of return on some of the platform costs, whether there should be performance bonuses or penalties, and a variety of additional details that would need to be addressed if fees to third parties are to be enacted upon implementation of the platform.

preference for authorization of a regulatory asset to track and collect, over time, certain cost elements rather than including the costs in current distribution rates.[12] Liberty Utilities, in its testimony, opined that the most appropriate route to provide cost recovery is via distribution rates as those rates are paid by all customers who will eventually have access to the data platform. However, Liberty witnesses went on to say that the timing of distribution rate cases may present less than optimal conditions for timely recovery of the data platform implementation costs and that the instant docket should address this issue. Liberty also supported imposing fees on third parties who use the system to extract customer data, including anonymized and aggregated data.[13]

Q. Please provide a brief summary of the initial positions of other parties regarding the issues related to cost recovery.

A. Mission:Data: Mission:Data proposes that the governance body be granted a budget cap of $250,000 annually under which the body could approve changes and improvements to the platform and in which prudence is pre-determined and the Utilities would be guaranteed recovery[14]. They also propose that "prudently-incurred costs for administering the GBC platform should be recovered from all ratepayers, and that the cost charged to customers or third parties for each use of the GBC platform should be zero."[15] They further propose a performance incentive for the utilities of up to 25% of the platform's first year costs if they meet or exceed certain performance metrics.[16]

[12] Testimony of Eversource/Unitil at page 54-55.

[13] Testimony of Liberty Utilities at Page 29.

[14] Testimony of Mission:Data at Page 72, lines 1-12.

[15] *Id.* at Page 72, lines 16-18.

[16] *Id*. Page 74, lines 2-4.

Clean Energy NH: CENH suggests that for the platform's initial start-up costs "the Commission could approve a specific limited budget for each utility that it deems is reasonable to meet the legislative objectives of SB 284. The utilities could then be confident that these investments are prudent, and will be recovered," and that the utilities could, after working with the Governance body, seek Commission approval for modification of these pre-approved budgets.[17] CENH suggests that once the Data Platform is established, operating costs could be recovered under a performance-based ratemaking approach based on the platform meeting certain performance metrics rather than through the traditional ratemaking process. In CENH's view, the utilities would be able to recover their implementation and maintenance costs if they meet the basic requirements established by the governance body and would receive additional shareholder compensation if they meet others goals that measure the ratepayer value and impact of the platform.[18]

GreeenTel: GreenTel states that the Commission should consider performance incentives for the data platform. Specifically, they recommend considering "the ability to rate base cloud-based software as a service (SaaS) technologies which will ensure the data platform is built leveraging the latest technologies."[19]

Local Government Coalition: Representative Kat McGhee: Representative McGhee suggests that there should be a performance based rewards system to the utilities for the platform meeting or exceeding system performance goals.[20] She also suggests that "If we are

[17] Testimony of Clean Energy NH at Page 30, lines 9-14.

[18] *Id*. at Page 30, line 19, through Page 31, line 23.

[19] Testimony of Greentel Group at Page 23.

[20] Testimony of Kat McGhee at Page 18, lines 1-9.

going to supply access to New Hampshire's energy data, the cost of development and ongoing maintenance should be absorbed into the cost of electric utility customer services."[21]

B. Platform Cost Recovery – Potential Recovery through SBC/LDAC

Q. Could the utilities recover costs of the energy data platform through the Systems Benefit Charge (SBC) and the Local Distribution Adjustment Charge (LDAC)?

A. The SBC was legislatively authorized by RSA 374-F:3, VI, which provides:

> A nonbypassable and competitively neutral system benefits charge applied to the use of the distribution system may be used to fund public benefits related to the provision of electricity. Such benefits, as approved by regulators, may include, but not necessarily be limited to, programs for low-income customers, energy efficiency programs, funding for the electric utility industry's share of commission expenses pursuant to RSA 363-A, support for research and development, and investments in commercialization strategies for new and beneficial technologies.[22]

Eversource currently funds the costs of its Customer Engagement Platform through the SBC, with an annual budget of approximately $600,000; initial integration costs associated with that customer data platform were approximately $3 million.[23] Staff believes this is one potential approach to consider for recovery of costs related to the development, implementation, and operation of the online energy data platform at issue in this proceeding.

Q. What approvals might be needed to recover the costs of the platform in this manner?

A. RSA 374-F:3, VI further provides that

> Legislative approval of the New Hampshire general court shall be required to increase the system benefits charge. This requirement of prior approval… shall not apply to the energy efficiency portion of the system benefits charge if the increase is authorized by an order of the commission to implement the 3-year

[21] *Id*. at Page 9, lines 8-11.

[22] The LDAC is the corresponding rate element through which the natural gas utilities collect costs related to the energy efficiency programs they administer.

[23] Attachment Rebuttal SRE-JM-4. Docket No. DE 17-136. Eversource Response OCA 2-10.

> planning periods of the Energy Efficiency Resource Standard framework established by commission Order No. 25,932 dated August 2, 2016, ending in 2020 and 2023, or, if for purposes other than implementing the Energy Efficiency Resource Standard, is authorized by the fiscal committee of the general court.

In light of this statutory provision, it seems likely that the SBC could only fund the platform if it were approved as part of the three year energy efficiency plan currently under review in DE 20-092, or, if it were explicitly authorized by the fiscal committee of the general court.

Q. What might be the advantage of the Utilities recovering the costs of the platform through the SBC and LDAC, rather than through distribution rates?

A. There is a chance that some functionalities offered by the data platform and certain functionalities currently offered by EERS marketing efforts and other customer data sharing efforts are, or could become, duplicative. For example, Eversource stated during the October 8, 2020 Technical Session in this docket that the license for their current Customer Engagement Platform (CEP) software is expiring in early 2021 and that they have released an RFP and received proposals for a new Customer Engagement Initiative. An Eversource representative stated that many of the proposals received by the company included Green Button Connect functionality as an option. It seems that if the costs and functionalities of the data platform, CEPs, and/or other customer data sharing efforts are reviewed in a more cohesive manner, there may be a reduced chance of incurring duplicative costs for redundant functionalities among software and data platform efforts.

Q. Are there any basic programmatic reasons to support consideration of the Energy Data Platform within the EERS and the corresponding SBC and LDAC charges?

A. There is at least one worth mentioning. It is our understanding that participation in several of the residential energy efficiency programs – the Home Performance with Energy Star (HPwES) and/or Home Energy Assistance (HEA) generally require the participant to provide

12 months of utility bills and other energy consumption information so that the energy auditor evaluating the premises for cost-effective improvements can use that data in the project-specific energy modeling. The platform's GBC functionality would make it easier for customers to obtain this data and transmit it to their auditor. Therefore, there is a direct connection between the need for the customer energy data and the SBC/LDAC energy efficiency program funding stream.

C. Platform Cost Recovery – User Fees

Q. You also mentioned charges to third parties for use of the energy data platform. Could the Utilities fully or partially offset the costs of the data platform with reasonable charges to third parties for use of the platform?

A. RSA 378:54 provides that "the Utilities may impose reasonable charges to third parties for access to data via the multi-use, online energy data platform." However, it does not seem likely that charges to third parties for using the data platform could fully provide the funds for development, deployment, and ongoing operational cost of the data platform. It is unclear how many users there would be, how often they would use the platform, how soon they would begin using the platform, or in exactly what manner they would use the available data. It is also unclear at this time exactly what functionality would be built into the platform and what data delivery tasks might still require significant additional expenses to develop more advanced data processes that would be of interest and value to third parties. It therefore does not seem possible to predict to the level of funding that such charges might provide or to what extent they could offset costs to ratepayers.

Q. Do other states have user fees associated with online energy data platforms?

A. In its direct pre-filed testimony, Mission:Data states that "no other jurisdiction to my knowledge charges a per-use fee for accessing a data-sharing platform. State commissions in California, Colorado, Illinois, New York and Texas have all determined that utilities' costs of administering customer energy data sharing systems should be socialized."[24]

Q. Do you have a preferred approach or a recommendation on this issue of user fees?

A. The Commission might initially order that all initial and ongoing costs of the data platform should be recovered from ratepayers rather than by charges to third parties. However, the Commission might authorize the Utilities to charge reasonable fees for certain platform uses and/or certain categories of users in the future. For example, if the delivery of aggregated and anonymized data is not fully automated by the platform and requires manual screening and/or analysis by the utility prior to delivery, it might be appropriate to establish a reasonable charge for providing aggregated data to offset the additional administrative expenses, rather than placing the burden on ratepayers.[25] We recommend that such charges should be developed only when there is more data and experience regarding the usage of the platform, rather than upon initial deployment. We also recommend that such charges be developed with some form of opportunity for stakeholder input to ensure that the charges are reasonable.

IV. PLATFORM GOVERNANCE

Q. Is there a consensus among parties on how the platform should be governed?

[24] Testimony of Mission:Data at page 73.

[25] *Id*. page 73 footnote 58 "I am aware that some jurisdictions, such as New York, permit utilities to charge a reasonable fee for certain *aggregations* of customer data where manual effort is required to analyze or process the request. However there is no charge for use of GBC systems in New York."

A. No. The testimony includes a variety of different proposals and suggestions regarding how the platform should be governed. There does appear to be a general consensus among parties that there should be at least one stakeholder group that could, at a minimum, attempt to resolve differences of opinion among the parties relating to platform development, prior to Commission review of any non-consensus issues. There also appears to be a general consensus that a stakeholder group should be structured in such a way that non-utility stakeholders are given input. However, the proposals vary regarding which stakeholders should be included in the group, how many should be included, and whether certain stakeholders should be granted decision making authority. In particular, there is disagreement regarding what proportion of representation should be granted to the Utilities compared to the representation of the platform's users and other non-utility stakeholders. There is also disagreement regarding the amount of autonomy the group would have, which specific aspects of the platform it would have authority/responsibility for, and whether the group would be given a certain amount of budgetary authority.

<u>A. Platform Governance – Positions of the Parties</u>

Q. Please provide a high-level summary of the initial positions of the parties regarding the membership, voting structure, and level of authority of a platform governance body.

A. **Eversource and Unitil:** Eversource and Unitil propose two working groups for the data platform: A "Governance Working Group" and an "Operations Committee." Eversource and Unitil described the makeup and role of the Governance Working Group (GWG) as follows:

> The GWG… would make recommendations to the Commission on a semi-annual or annual basis that the Commission could consider for implementation.

> The group could be comprised of the following: two representatives total from each utility involved with the data platform (a total of 6 representatives with the utilities with gas and electric operations being combined), three Commission-appointed stakeholder representatives for specified terms; two representatives from the Office of the Consumer Advocate; and up to three representatives from Commission Staff, as available. Recommendations will be made by general consensus, with dissenting opinions noted for consideration. Recommendations must have more than six 12 representatives supporting it to be submitted to the Commission.[26]

In testimony, Eversource and Unitil described the makeup and role of the Operations Committee (OC) as follows:

> The OC would consist of equal representatives of each utility and be responsible for drafting platform operation policy and procedures, technical design, scoping and pricing changes, change management, security management and recommendations on the feasibility and cost/benefit analysis of requests for enhancements or changes. The proposals of the OC would be submitted to the GWG should it want to add recommendations to OC proposals. Proposals of the OC would be submitted periodically or as needed to the Commission, but no more frequently than semi-annually.[27]

Eversource and Unitil later expanded on their OC proposal in response to discovery from Commission Staff:

> The Operations Committee (OC) would need approval of the Governance Working Group (GWG) for draft or revised operating policies and procedures; platform scoping and pricing changes; operating and capital budget revisions; and final decisions on security restrictions on users of the platform. The OC and GWG would need approval of the Commission on governance changes, and operating and capital budget approvals, as those items relate to the core mandate of the Commission's authority… The Operations Committee (OC) would make decisions on day-to-day operations and security including short term restrictions on platform access due to immediate cyber concerns; platform change management categorization (there is an expectation that change management approvals will vary with change complexity and risk); and cyber event classification and incident response. The OC would also be responsible for making technical design decisions where the decision affects the operations or security of the platform.[28]

[26] Testimony of Eversource/Unitil at page 50.

[27] *Id*.

[28] Attachment Rebuttal SRE-JM-5. Eversource and Unitil Response Staff 1-024.

Liberty Utilities: Liberty asserts that "Governance should be guided by multiple stakeholders, including the utilities, Commission Staff, the OCA, along with parties that may be interested in utilizing the platform." [29] Liberty suggests that a governance body for the data platform should perform in a manner that is a combination of the EESE Board and the not-yet-convened Grid Mod Stakeholder Group described in Order #26,358. Liberty further suggests the governance body should have a set number of members with voting rights, with a certain threshold of votes (such as a 2/3 majority) needed to move a recommendation forward to the Commission. [30]

Office of the Consumer Advocate: The OCA suggests that ideally, Utilities would play no direct role in the governance of platform planning and design, and that they would instead "essentially act as a service provider, accountable to a governing body."[31] The OCA recommends two separate governance groups for the data platform. One group would be tasked with planning and design and another group would be tasked with operations.

The OCA described the makeup and role of the planning and design group as follows*:*

> [The Commission should create] a nine-member stakeholder governance board, comprised of the Consumer Advocate or his designee (to represent the interests of residential customers), a representative of small commercial customers, a representative of large commercial customers, two members of the Commission Staff, two municipal representatives, and two representatives of firms that provide energy-related services to consumers that depend on access to data….Alternatively, the size of the stakeholder governance board could be increased to 12 voting members with a representative of Eversource, Liberty, and Unitil each given one vote." [32]

[29] Testimony of Liberty Utilities at Page 24, lines 15-18.

[30] *Id*. at Pages 24 and 25.

[31] Testimony of OCA at Page 89, lines 16-22.

[32] *Id*. at Page 90, lines 9-17.

The OCA suggests that the Commission should not initially determine how this body would operate, but rather, that "it would be better to allow this body to convene and work to decide for itself how it will operate, presumably according to bylaws or some similar governance document the body would adopt," subject to Commission approval.[33]

Regarding the OCA's proposed operations group, the OCA suggests that the Commission "create a platform operations committee that would be comprised of three utility representatives (one each from Eversource, Liberty, and Unitil), three representatives of third-party service providers reliant on the platform for data, and a tie-breaking representative of the Commission Staff. "[34] The OCA also recommends that the Commission "allow the operations committee to design its own operating rules in the first instance, subject to approval by the governance board and the Commission."[35]

Mission:Data: Mission:Data proposes that "the Commission appoint a Data Platform Committee comprised of two utility representatives, two DER representatives, and one representative from the Office of the Consumer Advocate."[36] It proposes an annual budget of $250,000 which the Committee could allocate for change requests with a presumption of prudence in each utility's next rate case for such allocations.[37] Under the Misson:data proposal, decisions would be made by majority vote, but that decisions could be appealed by any party, in which case the Commission would review the decision de novo.[38]

[33] *Id*. at Page 90, lines 19-22.

[34] *Id*. at Page 91, lines 11-14.

[35] *Id*. at Page 92, lines 4-6.

[36] Testimony of Mission:Data at Page 69, lines 18-21.

[37] *Id*. at Page 70, lines 1-9.

[38] *Id*. at Page 70, lines 9-12.

CENH: CENH states that the governance body of the data platform could include one or more seats for: Data Sources (including Utilities), State government (PUC, OCA, State Energy Manager), local government, academia and other researchers, advocacy groups, and third party energy service providers and DER representatives.[39] CENH makes no recommendation regarding whether the Utilities should have voting authority within such a governance body, but describe a potential conflict of interest.[40]

GreeenTel: GreenTel states that a governance body for the data platform should "appropriately represent the different parties."[41]

Local Government Coalition: Representative Kat McGhee: Representative McGhee suggests that a semi-autonomous governance body be granted a reasonable amount of rolling budgetary authority. She suggests a group comprised of 13 Members, with six third party energy stakeholders including one NH community power planner representative, four utility representatives, two State of NH representatives, and one ratepayer representative. She suggests a binding voting structure for conflict resolution, with conflicts elevated to the Commission if needed.[42]

Local Government Coalition: Dr. Amro Farid: Dr. Farid states agreement with the discussion of governance in the testimony of Kat McGhee, and adds that the platform's governance should include a wide variety of stakeholders with reference to 15 different

[39] Testimony of Clean Energy NH at Page 27, lines 11-20.

[40] Testimony of Clean Energy NH at Page 28 at line 10 through Page 29 at line 2.

[41] Testimony of Greentel Group at Page 23.

[42] Testimony of Kat McGhee at Pages 17 through 20.

identified categories of stakeholders. Dr. Farid also suggests consideration of the governance structure of ISO New England's data platform(s) as a relevant precedent.[43]

Local Government Coalition: Samuel Golding: Samuel Golding states that the platform's governance should be "primarily designed to fully engage and leverage market stakeholders in the decision-making process."[44] He suggests that the Commission consider a "market-based institutional decision-making framework" with reference to the Texas ERCOT model, and suggests that the Commission could "implement a similar market-based framework in this proceeding, giving due consideration to the elevated role that market participants, and CPAs in particular, should be expected to play within this governance framework."[45]

B. Platform Governance – Key Considerations

Q. Is there a relationship between the platform's cost recovery mechanism and platform governance?

A. Yes, the topics of governance and cost recovery are, to some degree, related. One example of this relationship is that if certain costs resulting from decisions made by a governance body are given the presumption of prudence, it might diminish the Utilities incentive to scrutinize and/or attempt to minimize these costs.

Q. Is there a relationship between the security of customer data and platform governance?

[43] Testimony of Dr. Amro Farid at Page 38.

[44] Testimony of Samuel Golding at Page 43, lines 15-17.

[45] Testimony of Samuel Golding at Pages 43 and 44.

A. Yes. Under RSA 363:37-38, the Utilities are tasked with the protection of customer data. It may not be appropriate to subrogate utility responsibility for such matters to a governance body on which they may have limited input or decision making authority. Conversely, it might not be optimal to create a scenario where the Utilities could be unnecessarily conservative about issues related to data security in a way that could negatively impact the user-friendly operation of the platform. If such a governance body and voting structure were considered by the Commission, it would need to carefully evaluate the balance of responsibilities assigned to each member.

Q. What might be the drawbacks of a governance structure that utilizes voting for binding decision making?

A. It seems unlikely that the individual governance body members would forfeit their right to raise an issue to the Commission, regardless of what voting structure is in place. Another drawback might be that in initially determining the composition of a governance body, the number of representatives from certain stakeholder groups assigned to the body might, in part, need to be determined with consideration of maintaining an appropriate balance of voting weight among the stakeholder types. It might instead be more advantageous to select the members of a governance body based on their possession of the variety of technical and non-technical knowledge, skills, and perspectives that are most likely to offer valuable input for data platform decisions, without potentially having to exclude a valuable stakeholder over the implications of the balance of voting power within the group structure.

C. Platform Governance – Stakeholder Working Group

Q. Are there other approaches to governance that the Commission might consider?

A. The Commission might consider enabling a governance body for the data platform in which decision making authority is only enabled when there is 100% consensus among all members of the body, with any non-consensus issues raised to the Commission. Such a structure could allow for maximum participation and input by stakeholder groups without concerns about disproportionate voting authority being granted to one certain stakeholder type and/or enabling the variety of potential perverse incentives described in parties' testimony. The fundamental drawback of such a group is that one member would be able to delay or elevate a decision to the Commission, regardless of whether a large majority of the group has come to agreement.

The Commission has convened working groups based on this model, most recently under the auspices of the Energy Efficiency Resource Standard and proposed grid modernization stakeholder group.[46] Within those processes, it is often the case that: (1) Staff chairs the working group; (2) Staff has the responsibility of elevating non-consensus issues to the Commission on behalf of the stakeholder group as well as reporting to the Commission on any assigned deliverables on behalf of the stakeholder group; (3) the Commission solicits comment on non-consensus issues elevated by Staff on behalf of working groups, providing stakeholders with an opportunity to be heard before issuing a decision; and (4) Staff is expected to exercise judgment in deciding at what point a consensus will not be reached and elevating an issue to the Commission, though nothing prevents another working group participant from doing so.

[46] Order Nos 26,095 (January 1, 2018) and 26,207 (December 31, 2018) (Establishing and continuing various working group for review of issues requiring further inquiry at time of settlement); Order No. 26,358 (May 22, 2020) at 24-36 (Establishing the grid modernization stakeholder working group).

V. PLATFORM ARCHITECTURE

Q. Is there consensus among the parties regarding the energy data platform's architecture or general design?

A. There does appear to be a general consensus regarding the use of an Agile software implementation approach, with many architectural design decisions made based on a set of user requirements which the platform should or must satisfy[47]. However, there are three closely-related aspects of the platform's architecture which do not appear to enjoy consensus currently.

The first aspect is whether the data platform's API "endpoint" (an API endpoint is a URL that enables the API to gain access to resources on a server – it's the internet address of the data source[48]) should be separate for each utility, for a possible total of five different API endpoints from which customers and/or third parties could retrieve data[49]. In the alternative, some parties have suggested that there should be a single API endpoint, which could require either that all the data be in a single, central data location, or that an "API-of-APIs" is developed with a layer that would effectively query the different utilities' APIs as appropriate, so that a data seeker could retrieve combined data from multiple Utilities' APIs in one request.

The second aspect of the platform's architecture in which there does not appear to be consensus is whether the platform should be built using a central database as proposed in the

[47] See Testimony of Everource/Unitil at page 18; Testimony of Clean Energy NH at page 14; Testimony of Clifton Below for Local Government Coalition at page 6.

[48] https://rapidapi.com/blog/api-glossary/endpoint/

[49] Under this approach, any third party seeking data from multiple Utilities would need to download data from each Utility individually using a separate API, and combine the data using their own efforts, their own software tools, and/or the services of a third party.

testimony of the OCA,[50] or it should employ a "virtual platform,"[51] as proposed in the testimony of the Utilities.

And, finally, the third aspect on which there is not consensus on whether the platform's Green Button Connect My Data API(s) and associated documentation should be made available on a dedicated platform web portal, or if they would be made available only by each Utility on its website.

<u>A. Platform Architecture – Positions of the Parties</u>

Q. What are the initial positions of the parties regarding these aspects of the platform's architecture?

A. The Utilities and the OCA have taken positions that differ in each of the three above-mentioned aspects of the platform. Generally, each other party either did not opine specifically about these aspects, or have suggested a platform architecture that includes parts of the Utilities' proposed architecture and parts of the OCA's proposed architecture.

The Utilities have stated a preference for the platform described in their testimony as "Option 2".[52] Generally, this is a platform which would provide one separate API for each utility and does not join them together with a final "API of APIs", does not utilize a central database, and does not utilize a central web portal. The Utilities stated that any or all of these three additions could raise the cost of the platform "substantially", but were not able to provide cost estimates. In response to Staff 01-17 (c), Eversource and Unitil stated that "A

[50] See Testimony of James Brennan at page 19 lines 3-8.

[51] See Testimony of Eversource/Unitil at page 29-30.

[52] See Testimony of Eversource/Unitil at page 25.

centralized data warehouse would increase the cost of the solution exponentially. It would generate costs for code and data storage, cyber security, system management, data retention, code management, and the labor associated with each of these as well."[53]

The OCA suggests that the platform should utilize a central database which would be the primary data source for one API endpoint for all NH utilities, which should be made accessible via a dedicated web portal. The OCA suggests that using a central database is the "least-cost" and "more future proof" approach to the platform's architecture, but was also not able to provide a cost comparison between any of these different architectural choices. We note that the OCA was the only party to propose in pre-filed testimony that the platform should include a central database.

Q. Might there be advantages to making these architectural decisions now, or could the features suggested by the OCA likely be added on later without significantly needing to change the underlying architecture of the platform to accommodate them (i.e. without incurring extraneous costs)?

A. Regarding the "API of APIs" and "Central Web Portal" decisions, in response to STAFF 1-017, Eversource & Unitil stated "additional features, defined in option 3 and/or others, would not be significantly impacted by implementing the changes in increments over time. In fact, it would reduce both risk and cost by ensuring what is implemented is truly what is needed."[54] We suggest that an "API of APIs" and/or a Centralized Web Portal could be features included in an RFP or RFI as a-la-carte options that are additional to the features of a minimum viable platform. The Commission could direct that the project enable one or both

[53] Attachment Rebuttal SRE-JM-6. Eversource and Unitil Response Staff 1-017.

[54] *Id*.

of these features upon implementation if they find that the additional benefits are likely to outweigh the additional costs. Otherwise, the Commission could determine that deferral of the implementation of these features to a later date is preferred.

Q. How should the Commission decide whether the platform should utilize a "Virtual" or a "Central Database" approach?

A. The OCA has suggested that there should be a "Design Pilot" which could, among other goals, provide experience that could assist in answering this question. They suggest that this design pilot is needed before releasing an RFP and/or the implementation of the platform should begin. They state that "I believe the risks of immediately moving forward with a full platform build exceed the benefits" and "It is my opinion that New Hampshire should hold off on a major RFP until the merits of a centralized platforms can be analyzed. I believe the cost of the proposed pilot are significantly outweighed by the potential benefits." However, they were not able to provide a cost estimate for a pilot. In response to Staff 1-11(c) the OCA witness states that "it is not possible to provide an estimate. In my opinion, and without having researched many variables, and without knowledge or consideration of the final negotiated pilot strategy, including duration and resources, a meaningful valuable pilot could be run with a budget range of moderate five figures to moderate six figures, give or take variances due to a multitude of factors unknown as of now."[55] It would be appropriate to seek further clarity on the estimated costs of a pilot before proceeding with this approach. We clarify that the OCA has described in their testimony multiple reasons why they believe a design pilot to be appropriate, and that gaining further information and experience to help resolve this particular issue is not the only goal of the proposed pilot.

[55] Attachment Rebuttal SRE-JM-7. OCA Response Staff 1-11.

Alternately (or after a design pilot if the Commission selects that approach), an RFP or RFI could seek separate cost estimates for a platform based on a centralized database as well as a virtual platform, and the costs of the proposals for each option could be compared. If one approach has a higher implementation and/or maintenance cost than the other, the Commission could decide whether that approach has benefits that outweigh its additional costs.

Q. Might further information become available from other states' efforts in the near future?

A. Yes. The State of New York State Public Service Commission, Case number 20-M-0082 is currently underway, which is a proceeding on "Motion of the Commission Regarding Strategic Use of Energy Related Data."[56] This proceeding is evaluating many of the same issues that are identified in New Hampshire's data platform law and have been raised in this docket, including the non-consensus issues identified in this testimony. New York Department of Public Service Staff have issues two whitepapers, one in regards to a "Data Access Framework,"[57] and another in regards to an "Integrated Energy Data Resource."[58] Both of these efforts might have substantial relevance to New Hampshire's DE 19-197 platform and its associated standards and requirements. Relevant and useful information might continue to become available by way of this proceeding, both during and after the remainder of DE 19-197's procedural schedule. An RFI was released for the Integrated

[56] NY PSC Case # 20-M-0082 is available at: http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?Mattercaseno=20-M-0082

[57] Attachment Rebuttal SRE-JM-8. Department of Public Service Staff Whitepaper Regarding a Data Access Framework.

[58] Attachment Rebuttal SRE-JM-9. Department of Public Service Staff Whitepaper Recommendation to Implement an Integrated Energy Data Resource.

Energy Data Resource in July 2020, with responses due in August. We recommend that the Commission remain mindful of similar efforts underway in neighboring states as it considers aspects related to development of the New Hampshire Platform, including platform architecture.

VI. CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your observations and recommendations.

A. In our testimony we described the different categories of costs that might be incurred for a statewide data platform and described how these costs might be minimized. We described three of the non-consensus issues relating to recovery of the platform's costs, the governance of the platform, and the architecture of the platform. We offered suggestions for how these issues might be resolved by the Commission, including a recommendation that the costs of the platform might be recovered by the utilities within their EERS Marketing budgets by way of the SBC and LDAC, a recommendation that governance of the platform might be accomplished by a non-voting stakeholder working group, and a recommendation that any remaining non-consensus architectural decisions could be included as options in an RFI or RFP to be evaluated after cost estimates are available.[59]

Q. Does that complete your testimony?

A. Yes.

[59] Consistent with our initial testimony, we recommend a two-step process for approval of the platform and that, to determine the likely costs of the platform, the platform operators consider issuing an RFP/RFI for platform development which includes a scope of work that is extensible but focused on a the minimum viable platform.

GREEN BUTTON COST-BENEFIT ANALYSIS REPORT

Submitted to: **ONTARIO MINISTRY OF ENERGY**
Conservation and Energy Efficiency Branch

Prepared by:

dunsky ENERGY CONSULTING

Revised: October 2017

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INTRODUCTION

Ontario's Ministry of Energy has hired Dunsky Energy Consulting to support its efforts in developing policy recommendations for the potential implementation of Green Button for electricity, natural gas, and water utilities in Ontario. Specifically, our team is conducting a cost-benefit analysis and facilitating stakeholder consultations on behalf of the Ministry. The Ministry is taking on an exciting leadership role in this area, as no jurisdiction has attempted a quantified cost-benefit analysis of the Green Button standard to date.

This report includes the following information:

- The **cost-benefit analysis report,** which outlines how the Green Button cost-benefit analysis was developed including:
  - **Overview of cost-benefit analyses in general:** principles, strengths, and limitations of cost-benefit analyses (not Green-Button-specific);
  - **Green-Button cost-benefit analysis assumptions:** generic assumptions and inputs used in our modelling (not scenario-specific); and
  - **Key scenarios:** assumptions and inputs used in our modelling related to specific scenarios.

- **Appendix A** includes the Cost-Benefit Analysis slide deck, which was presented to stakeholders during the second round of consultations, held July 18th to 27th.

- **Appendix B** includes descriptions of, and sources for, the assumptions built into the cost-benefit analysis model and is designed to provide the Ministry with an understanding of how our research informed the analysis and the inclusions therein.

- **Appendix C** provides an overview of the components of the costs and benefits that are included in the model. To avoid double-counting costs and benefits, many important considerations of a Green Button initiative were required to be rolled up into larger categories. This table is intended to demonstrate that these costs and benefits have not been excluded from the analysis; rather, they have been included at a higher level.

- **Appendix D** explains the methodology, assumptions, and inputs used to estimate the conservation costs and benefits, including greenhouse gas reductions, related to the implementation of Green Button.

- **Appendix E** includes additional scenario analyses using a real societal discount rate of 3.5%, which has been used by the Ministry of Energy in other recent analyses.

COST-BENEFIT ANALYSES

This section explains how cost-benefit analyses in general are structured, as well as alternatives and limitations.

OVERVIEW

The cost-benefit analysis (CBA) developed to assess the potential implementation of Green Button in Ontario follows the general principles of cost-benefit analyses: it provides a common ground to compare the costs incurred by each scenario under consideration to the potential benefits that are expected to materialize as a consequence of that scenario. One of the key strengths of a CBA analysis is that it provides a coherent and consistent view of benefits and costs using a common expression. In most cases the common expression is monetary value, which means that all costs and benefits in the analysis must be expressed as a monetary value. If they cannot be expressed in this way, they cannot be included in the analysis. For example, time can be converted by utilizing assumptions for hourly or daily labour costs.

CBA analyses are based on a set of fundamental parameters and considerations. Some of the key ones are the following:

- Benefits and costs are expressed in constant dollars, taking into consideration the time-value of monetary flows.
- CBA analyses must be balanced (i.e., the analysis should strive to account for all costs and benefits of any specific component).
- Its boundaries must be clearly defined, to capture and express costs and benefits within these boundaries.
- Double counting of costs and benefits must be avoided. This can be challenging when benefits can be expressed in different fashions or accrue to different stakeholders (i.e., if any components are included at a more granular population than the general boundary of the analysis, they should not be included in a broader stakeholder category).
- CBA analyses cannot provide a perfect appraisal of all present and future costs and benefits. Recognizing this, effort should be focused on the evaluation of costs and benefits with a material impact on the expected results.
- CBA outcomes rely on the accuracy and quality of the inputs used. Data quality can be higher when it is possible to draw from similar types of analyses conduct in other jurisdictions or when detailed, market-specific data is available.

BENEFIT-COST RATIOS

Benefit-cost ratios are the result of a cost-benefit analysis. To calculate them, total benefits (in dollars) are divided by total costs in the following way:

$$R = \frac{B}{C}$$

If the ratio is positive, it means that the benefits outweigh the costs, so the initiative being analyzed is cost-effective. If it is negative, the costs exceed the benefits and the initiative is not cost-effective.

Here is an example:

$$B \quad C \quad R = \frac{\$4{,}000{,}000}{\$1{,}000{,}000} = 4$$

In this example, the benefits outweigh the costs by 4 to 1, so the initiative being analyzed is cost-effective.

ALTERNATIVES

Alternatives to CBA exist that use a different denominator for the benefits where appropriate. As an example, cost-effectiveness analyses for energy efficiency programs can be expressed in $/unit of energy saved, and similar constructs are used for economic analysis in other spheres ($ per life-year saved, $ per GHG emissions reduction, etc.). When assessing the potential implementation of a Green Button policy, since the vast majority of benefits can be readily expressed in a monetary figure, this is the most appropriate denominator to be used for a CBA analysis.

LIMITATIONS

BENEFIT-COST RATIOS

The cost-benefit results (in the form of benefit-cost ratios) are presented at the societal level, not for individual sectors or customer groups. This is because there are numerous overlapping and multi-tiered costs and benefits that cannot be broken out. For example, setup costs are incurred at the utility level (therefore all customers), but only a subset of customers see associated process efficiencies. Conversely, some customers will incur costs, but other customers will receive benefits related to that investment.

While we are unable to present balanced cost-benefit ratios at the sector or customer-group level, the results have been built up from inputs at those levels rather than developed from a top-down approach. We are therefore able to present the dollar values used as inputs in key scenarios to provide a sense of scale.

LEVEL OF GRANULARITY

CBA analyses provide a reasonable estimate of the best alternatives to be considered. However, they should be used to inform and guide decisions, not to dictate them. Components and considerations not included in the CBA analysis (including qualitative benefits) should also be accounted for in the decision-making process.

It is also important to note that Green Button is a relatively new opportunity, and little documented and verified data exists at the granularity that exists for other types of CBAs. The information we gathered was largely new and primary-source based, and data for some sectors, costs and benefits is more widely available than others. Where detailed, granular data does not exist, or the project scope did not allow for in-depth research, our team therefore developed assumptions and proxies.

For this reason, the analysis highlights scenarios that are cost-effective and ones that are not. However, the results should not be interpreted as exact; they should be interpreted as indicative. The inputs we gathered and developed are appropriate for a policy-level analysis designed to determine whether the benefits of a Green Button implementation outweigh the potential costs. However, they are not developed at the granularity that an actual implementation plan would require.

Where costs and benefits have been broadly quantified based on limited data availability, we recommend caution in the interpretation of the results. This is especially the case with results for which the benefit-to-cost ratio is close to one, as small deviations from the assumptions used can lead to different conclusions (e.g., the benefit/cost ratio can fall or rise above one if assumptions change).

RESEARCH SOURCES

Our team conducted secondary research and literature reviews that included evaluation and research reports, utility filings and reports, Statistics Canada data, conservation and demand management (CDM) and demand-side management (DSM) programs, and other sources.

We also generated key inputs and assumptions through a series of consultations, surveys and interviews with stakeholders. Information on this source of primary data is provided below, and the assumptions developed from each source is provided in Appendix B.

STAGE ONE CONSULTATIONS

We obtained initial input from stakeholders on general costs and benefits they could experience from a Green Button implementation. This stage was designed to ensure we research the appropriate topics and details. Eighty-nine organizations attended these sessions, with the breakout by stakeholder group provided below.

Figure 1. Breakdown of Stakeholder Groups Attending Stage One Consultations

STAGE ONE WORKBOOKS

We asked a series of questions asking stakeholders to quantify costs and benefits they could see as a result of a Green Button implementation. Questions focused on how and for what purposes utility data is requested or shared, challenges with accessing or providing data, time and effort that could be saved by accessing data via Green Button, and other potential benefits such as access to additional insights in energy or water use, greater potential for taking action to save energy or water, and other outcomes. We received thirty workbooks in total, with the cross-section of stakeholder groups provided in figure 2 below.

Figure 2. Breakdown of Completed Workbooks by Stakeholder Group

INTERVIEWS

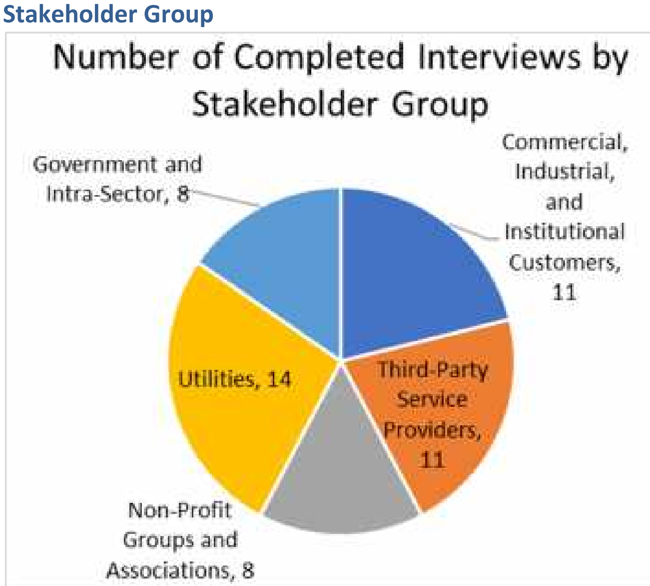
The Stage One Consultations and workbooks were designed to ensure we understood the potential scope of costs and benefits for a Green Button implementation. However, to obtain more granular data and inputs with which to assess the costs and benefits, our team conducted interviews with multiple organizations in each stakeholder group.

For interviews with utilities:

- We interviewed small, medium, and large electricity and water utilities as well as both large natural gas utilities to ensure we captured differences between how each size and type would be impacted by a Green Button implementation.
- We interviewed both utilities involved in Ontario's Green Button Connect My Data Pilot in order to obtain as much detail as possible on the actual implementation experience in Ontario, in particular for the costs of implementing Green Button Connect My Data (including Extract, Transform, and Load (ETL) protocols, integration with customer portals, meter data, external testing and validation, etc.).

These semi-structured interviews went into more detail in terms of quantifying the costs and benefits identified in the earlier consultations and workbooks. Our team completed 52 interviews across the range of stakeholder groups, with a higher percentage completed with groups identified as having the greatest potential benefits and/or costs: Commercial, Industrial and Institutional customers, utilities, and third-party service providers (consultants, energy efficiency services organizations, app developers, and hosted solution providers), as highlighted in figure 3 below.

Figure 3. Breakdown of Completed Interviews by Stakeholder Group



UTILITY INFORMATION TECHNOLOGY SURVEY

An important component of the cost-benefit analysis was understanding the information technology (IT) infrastructure of utilities. Because benefits arising from Green Button change based on the type and frequency of utility metering and meter reads and other utility IT considerations, we sent surveys to electricity, natural gas, and water utilities. The surveys included the following question categories:

Category Type	Information Sought
Consumption Data	Type of metering infrastructure by customer segment
	Number of installed meters and sub-meters by customer segment
	Typical time intervals for meter reads and whether estimates are used, by customer segment
	How meter data is managed for General Service and Large User customers (specifically whether or not it is outsourced or done in-house)
	Availability and frequency of access of online customer portals
	Billing frequency and format
	Billing processes including whether or not it is conducted by a third party
	Customer access to consumption data, including availability, format, process, granularity, frequency, and cost
	Processes for authorized third-party access to customer utility data, including time and effort required to grant approvals
	Percentage of customers requesting access to their consumption data in a machine-readable form, by customer segment, and the cost and effort of fulfilling such requests
Generation Data	Availability of customer generation data (for applicable customers), by customer segment
	Level of granularity and frequency of customer generation data
	Percentage of customers requesting access to their generation data in a machine-readable form, by customer segment, and the cost and effort of fulfilling such requests
Additional Questions	Current investment in smart meters, by customer segment
	Planned meter and IT investment, including smart meters (by customer segment), meter data management infrastructure, billing, customer portals

These surveys were used, in combination with other sources, to develop estimates of the number of water utilities with metering infrastructure, accounts by utility type and customer segment, penetration of submeters in buildings and facilities, percentage of customers currently accessing utility data in electronic format, and annual cost reductions by utility type and size.

Overall, our team received 61 completed surveys, broken down as follows:

- 33 electricity utilities (46 percent of possible utilities);
- 2 natural gas utilities (67 percent of possible utilities); and
- 26 water utilities (5 percent of possible utilities).

SOLUTION PROVIDER SURVEY

Additional data was also required to estimate the costs for developing, hosting, and maintaining the Green Button platforms. Because we required detailed cost information that is difficult to gather via phone interview, we sent surveys to eleven solution providers, from which we received two submissions. The surveys asked for estimates of the following costs for each of two scenarios:

Scenarios:

1. Implementing Green Button Connect My Data as a hosted solution for each utility (e.g. if each utility was responsible for hiring a firm to implement Green Button Connect My Data).
2. Implementing Green Button Connect My Data as a hosted solution for a group of utilities (e.g. if a hosted solution provider were hired to implement it for a group of utilities or for the entire province).

Information Requested:

- Fixed and variable costs for each utility if hired on an individual basis, by utility type, size (small, medium, or large), or group;
- Time required to set up and launch the platform; and
- Assumptions, including whether or not the provider is hosting Connect My Data or is installing Connect My Data software.

This information was used to develop estimates for the costs of developing and hosting a Green Button Platform. Rolled-up, not itemized, costs were requested; they included front-end solutions, cloud services, platform costs, development and testing, and registration.

GREEN BUTTON COST-BENEFIT ANALYSIS

The following sections describe 1) the general assumptions used in the Green Button cost-benefit analysis and 2) inputs and assumptions used in modelling specific scenarios.

STAKEHOLDER GROUPS

There are five key stakeholder groups involved in the analysis, with further categorization within the groups, as outlined below[1]:

Stakeholder Group	Stakeholder Sub-Group		Additional Considerations (if applicable)	
Customers	Commercial	Large	Owners/Managers; Tenants	Existing users of utility data; New users of utility data
		Small	Owners/Managers; Tenants	Existing users of utility data; New users of utility data
	Large Industrial		Owners/Managers; Tenants	Existing users of utility data; New users of utility data
	Institutional		Owners/Managers; Tenants	Existing users of utility data; New users of utility data
	Residential		Owners/Managers; Tenants	Existing users of utility data; New users of utility data
Third-Party Service Providers	Energy Efficiency Services			
	Hosted Solution Providers			
	Application Developers			
	Consultants			
	Renewables			
Non-Profit Groups and Associations	Associations			
	Non-Profit Organizations			
Utilities	Electricity Utilities	Large; Medium, Small		
	Natural Gas Utilities	Large; Medium, Small		
	Water Utilities	Large; Medium, Small		
Government and Intra-Sector				

[1] Note that stakeholder groups do not necessarily align with higher-level groups used for stakeholder consultations and workshops – these sub-groups align with how research for the cost-benefit analysis was conducted.

QUANTITATIVE AND QUALITATIVE BENEFITS

We considered multiple costs and benefits in our analysis, some of which are direct results of a Green Button implementation, others that are prompted by (but not automatically resulting from) Green Button, and others that are important but cannot be quantified. For this reason, we group them in the following way:

Table 1. Grouping of Costs and Benefits

QUANTITATIVE		QUALITATIVE
Direct (Layer 1A)	**Indirect (Layer 2A)**	**(Layer 2B)**
Benefits and costs are a direct result of Green Button implementation Monetary value can be estimated based on available information	Indirect consequence of Green Button implementation Require an additional external influence or decision point in order to materialize Monetary value can be estimated based on available information	Not included in Cost-Benefit Model Reported as “additional costs/ benefits” Used in overall analysis and policy recommendations

SCENARIOS

Two core considerations in the Green Button Cost-Benefit Analysis were the potential implementation of either Green Button Download my Data (DMD) or the implementation of both Download my Data and Connect my Data (CMD). For clarity, these are the definitions we used, per the Ministry’s definition:

Table 2. Green Button Option Definitions

Option	Details
Green Button Download My Data (DMD)	• Provides customers with the ability to download their utility data directly, through their utilities’ websites • Data is downloaded in XML and is provided in a consistent format
Green Button Connect My Data (CMD)	• Provides customers with the ability to share their data with solution providers/app developers and compatible databases in an automated way, based on consumer authorization • Process follows Privacy By Design principles

For each of these options, we then layered additional dimensions:

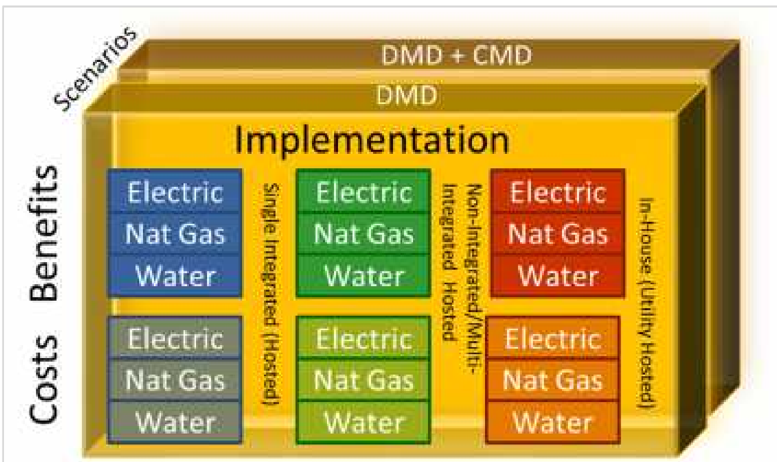
- **Utility Type:** Electricity, Natural Gas, Water
- **Implementation Type:** Single Integrated (Hosted), Multi-Integrated (Hosted), Non-Integrated (Hosted), In-House

For the implementation types, we used the following definitions:

- **Single Integrated (Hosted):** One Hosted Software as a Service (SaaS) provider implements Green Button for all utilities, incorporating one platform for each utility type (three platforms in total).
- **Multi-Integrated (Hosted):** A limited number of Green Button hosted SaaS platforms are used by all utilities.[2] This implementation assumed five implementation platforms for electricity and water utilities and two for natural gas utilities.
- **Non-Integrated (Hosted):** Each utility has the option to develop/procure its own Green Button SaaS hosted platform. One platform per utility was assumed, for 591 platforms in total.
- **In-House:** Each utility develops its own platform on its own IT systems. One platform per utility was assumed, for 591 platforms in total.

Overall, the layering (and resulting combinations of scenarios) can be conceptualized in the following way:

Figure 4. Cost-Benefit Analysis Scenarios



GENERAL INPUTS AND ASSUMPTIONS

UTILITY TYPE

The inputs for each utility type (electricity, natural gas, and water) are critical because Green Button would be implemented by utilities. Our general assumptions are:

[2] This was a hypothetical scenario to demonstration potential synergies in limiting the number of providers; the same assumptions were used for this scenario as for the non-integrated, with the difference being the number of platforms developed and integrated.

Table 3. Utility Input Assumptions

Utility Type	Key Factors in Analysis	Details	Source (if applicable)
Electricity	Utility Population/Sizes	• 7 Large, 21 Medium, 44 Small	• OEB 2014 Yearbook of Electricity Distributors
	Metering Infrastructure	• All are metered • Most have completed smart meter implementation for Residential and Small Commercial • Sub meters exist for many buildings (but unknown to what extent by utilities)	• Utility IT survey • Interviews with stakeholders
	Total Number of Accounts	• 5,162,768 accounts	• OEB 2014 Yearbook of Electricity Distributors • Utility IT survey
Natural Gas	Utility Population and Sizes	• 2 Large, 1 Small	• OEB 2014 Yearbook of Natural Gas Distributors
	Metering Infrastructure	• All are metered • Combination of Automatic Meter Reading (AMR) and analog meters	• Consultations with utilities
	Total Number of Accounts	• 3,423,622 accounts	• Utility scorecards – Ontario Energy Board • Union Gas and Enbridge Gas filings
Water	Utility Population and Sizes	• 39 Large, 91 Medium, 385 Small (only metered utilities were included in the analysis)	• Watertap Ontario
	Metering infrastructure	• All large and medium utilities metered • 70% of Ontario's 550 small water utilities assumed to be metered (resulting in the 385 indicated above) • Analog meters	• Utility IT Survey
	Total Number of Metered Accounts	• 4,955,366 metered accounts	• Residential: based on population in each municipality and average number of individuals per household in Ontario (Statistics Canada) • Commercial: based on proportion of electricity to water accounts

ADDITIONAL INPUTS

Separate from the utility types, our team had to make decisions as to the information and inputs to include in the analysis based on the data available or accessible through research and interviews, as well as the requirements of the analysis. These types of inclusions (and exclusions, as applicable) are provided in Table 4: General Inputs.

A NOTE ABOUT NET-PRESENT VALUE CALCULATIONS AND SOCIETAL DISCOUNT RATE

The economic analysis of Green Button was conducted based on the net present value of the benefits and costs streams generated by the program. All benefits and costs monetary streams were assessed in real values to isolate them from the impacts of inflation and to account for the uncertain timing of the Green Button implementation. Conducting cost-effectiveness analysis using real values is a leading industry practice and recommended in the IESO Conservation & Demand Management Energy Efficiency Cost Effectiveness Guide of June 2015.

The monetary streams were then discounted to the first year of implementation, using a real social discount rate of 2%. The proposed discount rate was informed by the long-term Ontario Global bonds maturing in December 2046 (Series no. DMTN228) with an interest rate of 2.9%, the inflation rate in June 2016 of 1.7%, and the IESO real social discount rate of 4% applied for utilities' CDM initiatives. Monetary values are expressed in 2016 dollars.

Although there are no set criteria to define an appropriate discount rate for government-led energy efficiency initiatives, the public benefit perspective of Green Button advocates for the use of a long-term, risk-free discount rate attuned to the provincial government's long-term interest rates. However, considering that this would translate into a real discount rate of 1.2%, and considering the discount rates used for CDM initiatives of 4%, a more conservative real discount rate of 2% was applied to the Green Button economic analysis.

Relevant sources are as follows:

- Province of Ontario Bond Issues Details: http://www.ofina.on.ca/pdf/bond_issue_details_DMTN228_to_R19.pdf
- 2016 Consumer Price Index and Inflation Rates for Ontario: http://inflationcalculator.ca/2016-cpi-and-inflation-rates-for-ontario/
- Conservation and Demand Management Energy Efficiency Cost Effectiveness Guide: http://www.ieso.ca/-/media/files/ieso/document-library/conservation/ldc-toolkit/cdm-ee-cost-effectiveness-test-guide-v2-20150326.pdf?la=en

Table 4. General Inputs

Category	Assumption/Consideration	Status	Rationale	Source (if applicable)
General Inputs	Metered utility types beyond electricity, natural gas, and water	Excluded	Lack of data	
	Societal discount rate	Included	The final policy will provide benefits and costs for Ontario as a whole.	Adjustment to IESO real discount rate (CDM EE Cost-Effectiveness Test Guide) to reflect conservative view of 30-year Ontario real bond rates of 1.2%)[3]
	Participation in Green Button based on Rogers' Diffusion of Innovation (varies by cost/benefit category)	Included	Used in Energy Efficiency Forecasting. Parameters fitted to observed and expected behaviours	Rogers' Diffusion of Innovation
Green Button Standard	Updates to Ontario Green Button architecture	Excluded	Out of scope	
	Single version of the standard for deployment	Included	Ensures consistency among utility implementations	
	Green Button certification costs (utility or solution provider/app developer)	Excluded	Lack of data, certification approach and costs under development at time of analysis	
	Application registration platform costs	Excluded	Not a fundamental requirement and lack of data	
Metering Infrastructure	Infrastructure upgrades (i.e., upgrading to smart meters or installing meters)	Excluded	Out of scope	
	Existing sub-meters: benefits	Included	Small, but quantifiable	Interviews with stakeholders
	Existing sub-meters: costs	Excluded	Initial research indicates lack of additional costs to implement Green Button for existing sub-meters	Interviews with stakeholders

[3] For additional analyses using a real societal discount rate of 3.5%, which has been used by the Ministry of Energy in other recent analyses, please see Appendix E.

Category	Assumption/Consideration	Status	Rationale	Source (if applicable)
Energy Inputs	Duration limited to analysis periods of 5 and 10 years (no end effects)	Included	Conservative assessment and unknown lifetime for retrofit measures	
	Energy retrofit costs ($/kWh or $/annual m^3 saved) accrued at the same time as benefits materialize	Included	Aligns benefits and costs for a more consistent reporting of results	Ontario gas utility's DSM Plan; Canadian Jurisdictions' Electricity DSM Plans (e.g. New Brunswick, Nova Scotia)/Potential Studies

COSTS OF A GREEN BUTTON IMPLEMENTATION

Quantitative costs of implementing and managing a Green Button Connect My Data solution, whether direct or indirect, can be categorized into three main components:

1. **Set-up**: Costs required to develop the Green Button platform (setup can be administered either by utilities or third parties).
   - Setup costs are largely related to developing the Green Button platform, so the costs are incurred for each platform developed. This means they vary based on the implementation model selected (single-integrated hosted, multi-integrated hosted, non-integrated hosted, and in-house), but not by utility size, type, or other consideration.

2. **Integration**: Costs incurred to integrate Green Button with utilities' data systems and processes.
   - These costs vary based on the utility size, reflecting the complexity of systems required to integrate with the Software as a Service (SaaS) hosted implementation platform. As part of the analysis, we also assumed the integration costs would vary based on the implementation scenario being assessed, with increased costs if utilities are required to develop and test all solutions without guidance from a SaaS hosted implementation provider.

3. **Ongoing annual costs**: Costs, expressed as a unit cost (cost per participating account) required to maintain the system and manage third-party solution provider application registration.
   - Similar to integration costs, the analysis assumes that annual costs vary based on the type of implementation model selected (single-integrated hosted, multi-integrated hosted, non-integrated hosted, and in-house). This reflects the range of values reported by third-party hosted solutions providers, with a lower unit cost (cost per participating account) for fewer SaaS platforms and a higher unit cost for individual in-house implementations. Details are provided in the Costs table below.
   - Retrofit costs are also included in this category as an indirect cost, since increased access to utility data is expected to drive interest in energy efficiency. The analysis is agnostic as to whether the retrofits occur outside of or through utility CDM programs, as total costs (whether incurred by the utility or the participant) are included, regardless of the source of funds.

These costs are incurred regardless of specific implementation scenario, although their magnitude changes based on the particular scenario being analyzed. In this section, we provide individual cost inputs to the analysis. Costs associated with specific implementation scenarios (combinations of inputs) are provided in the following section.

COST CATEGORIES, DEFINITIONS AND APPLICABILITY

Table 5 provides an overview and clarifying information regarding the various categories of costs, including definitions and the groups to which the costs apply.

Table 5. Cost Categories, Definitions and Applicability

Category	Cost	Definition	Impacted Groups[4]	Grouping
Platform Setup Costs	Front-end solutions	Interfaces and applications that users interact with directly	Utilities (can be via Software as a Service Green Button Implementation Providers)	Direct, Quantified
	Cloud services	Computing resources and services that support the deployment of Green Button and provide access to its applications, resources and services	Utilities (can be via Software as a Service Green Button Implementation Providers)	Direct, Quantified
	Green Button platform	The technical foundation that allows multiple products (such as Green Button applications) to be built within the same framework and execute successfully	Utilities (can be via Software as a Service Green Button Implementation Providers)	Direct, Quantified
	Development and testing of the services to manage third-party (solution provider) applications	Management of integration, registration, risk assessment, issues, etc.	Utilities (can be via Software as a Service Green Button Implementation Providers)	Direct, Quantified
	Testing of required security and privacy mechanisms and protocols	Required for ensuring mechanisms and protocols are acceptable	Utilities (can be via Software as a Service Green Button Implementation Providers)	Direct, Quantified

[4] Party incurring the costs

Category	Cost	Definition	Impacted Groups[4]	Grouping
Utility Integration Costs	Customer information system extract, transform and load (ETL) protocols	Protocols for the functions required to pull data from a utility's database into another database	Utilities (can be via SaaS Green Button Implementation Provide	Direct, Quantified
	Other integration costs such as integration with customer portals, meter data, external testing and validation, etc.	Testing and resolving issues with the connections between utility data systems and external systems via Green Button	Utilities	Direct, Quantified
Annual Variable Costs by Participating Customer	Maintenance and ongoing operations	Ongoing modification to address issues, improve performance, or incorporate changes to the standard	Utilities	Direct, Quantified
Retrofit Costs	Unit Costs of Retrofit Activity ($/conservation benefit)	Unit costs are the costs of an activity (e.g. retrofits) divided by the energy saved. Increased energy efficiency retrofits are expected to occur with a Green Button implementation, so related costs must be included to provide a balanced analysis.	Customers	Indirect, Quantified

COST INPUTS, SOURCES AND ASSUMPTIONS

Table 6 includes key inputs for each cost component, including sources and assumptions our team used to develop them.

Costs associated with solution provider/app developer registration with utilities were excluded because they were outside of cost-effectiveness testing parameters (they are built into the solution providers' costs).

Table 6. Cost Inputs, Sources and Assumptions

Cost Component	Unit Cost	Assumption/Considerations	Sources [5]
Platform Setup Costs – Green Button Platform	$50,000/ platform	• Assumes fixed cost per CMD implementation platform for setup (number of platforms drives costs). • Significant differences in values were quoted by different providers (from $0 to $50,000), but the value selected is a reasonable representation because it includes all services, including third-party registration.	• Based on discussions with hosted Software as a Service (SaaS) providers and solution provider survey.
Utility Integration Costs – Hosted Solution Implementation Scenarios (Multi-Integrated, Single Integrated, and Non-Integrated)	Large Utilities: $225,000/utility Medium Utilities: 72,000$/utility Small Utilities: 22,500$/utility	• Costs vary based on utility size, which reflects complexity of utilities' IT infrastructure. • Utility type does not alter the assumptions as it is IT, not energy, factors that impact the costs.	• Based on stakeholder interviews (specifically on Ontario's CMD pilot project experience).
Utility Integration Costs – Impact of in-house Implementation Model	Integration costs increase by 33% in comparison to the Single Integrated Hosted Solution implementation scenario	• Costs vary based on utility size, which reflects complexity of utilities' IT infrastructure. • Cost inefficiencies occur because software hosting is not part of utilities' core business.	• Based on stakeholder interviews (specifically on Ontario's CMD pilot project experience).

[5] When interviewees provided a range of responses our team used the mid-range unless, based on our experience and knowledge, it appeared overly optimistic, in which case we selected a higher end of the range.

Cost Component	Unit Cost	Assumption/Considerations	Sources [5]
Annual Variable Costs by Participating Customers	**SaaS Multi- and Non-Integrated Hosted Implementations:** $1/participating customer	• Fixed costs per participant vary by implementation scenario: assumes economies of scale between implementation scenarios (the fewer the number of platforms, the greater the cost efficiencies related to management of the platform and system). • Assumes mid-range of information provided by Software as-a-Service providers. • Includes general operational costs and costs to support solution provider/app developer registration.	• Professional judgment based on information provided by SaaS providers during stakeholder interviews.
	SaaS Single Integrated Hosted Implementation: $0.80/participating customer	• Fixed costs per participant vary by implementation scenario: assumes economies of scale between implementation scenarios (the fewer the number of platforms, the greater the cost efficiencies related to management of the platform and system). • Includes general operational costs and costs to support solution provider/app developer registration. • The input selected reflects operational maintenance efficiencies compared with the multi- and non-integrated implementations.	• Representative of information provided by SaaS providers during stakeholder interviews.

Cost Component	Unit Cost	Assumption/Considerations	Sources [5]
	In-House Utility Implementations: $1.20/participating customer	• Fixed costs per participant vary by implementation scenario: assumes economies of scale between implementation scenarios (the fewer the number of platforms, the greater the cost efficiencies related to management of the platform and system). • Analysis assumes high range of information provided by Software as-a-Service providers in order to be conservative and based on professional judgment.	• High range of information provided by SaaS providers during stakeholder interviews.

Retrofit Costs – Customers' energy efficiency upgrades resulting from access to data	**Residential Electricity Customers:** $0.65/$ value of benefits
	Residential Natural Gas and Customers: $0.69/$ value of benefits
	Non-Residential Customers (all utility types): $0.50/$ value of benefits
		• Annual levelized costs.
		• Costs are in relation to level and extent of retrofit activity.
		  ◦ Full retrofit costs are included regardless of whether customers participate in a CDM/DSM program or not (i.e. if costs are partially paid by the utility or fully by the customer).
		  ◦ Behavioural and operational savings are assumed to be implemented by the customer at no cost because they result from a change in procedures or behaviour rather than a solution that requires a capital outlay.[6]
			• Ontario utility and other Canadian CDM/DSM Plans (e.g. New Brunswick, Nova Scotia); Potential Studies

[6] Some process efficiencies could require additional resources or labour, but this is expected to be minimal and has therefore been excluded from the analysis.

BENEFITS OF A GREEN BUTTON IMPLEMENTATION

Quantified benefits from a Green Button implementation can be categorized into **two main categories:**

- **Operational Efficiencies**
  - Process efficiencies in accessing consumption, billing and generation utility data;
  - Reduced customer care effort; and
  - CDM/DSM program efficiencies and innovations.

- **Conservation / Energy Efficiency**.
  - Energy and water savings from behavioural changes resulting from additional access to utility data; and
  - Energy efficiency retrofit improvements resulting from additional access to utility data.

These benefits are incurred regardless of specific implementation scenarios, although their magnitude will change based on the particular scenario being analyzed. Benefits associated with specific implementation scenarios (combination of inputs) are provided in the following section.

BENEFIT CATEGORIES, DEFINITIONS AND APPLICABILITY

Table 7 on the following page provides an overview and clarifying information regarding the various categories of benefits included in the analysis, including definitions and the groups to which they apply.

Table 7. Benefit Categories, Definitions and Applicability

Category	Benefit	Definition	Impacted Groups[7]	Grouping
Operational Efficiencies	Utility consumption, billing and generation data process efficiencies and Ongoing utility consumption monitoring and benchmarking	• Process efficiencies for customers and consultants/service providers include efficiencies in energy audits; reduced effort/cost for energy tracking, reporting, and benchmarking; reduced effort to consolidate/ standardize data across facilities; reduced effort to "clean" and quality-check data; reduced effort to authorize data sharing; and access to increased frequency and granularity of utility data. • The benefits relate to customers who require data for their own internal use (e.g. for internal benchmarking or operational requirements) or who will need to comply with the Ministry of Energy's Large Building Energy and Water Reporting and Benchmarking initiative under *Ontario Regulation 20/17, Ontario Reporting of Energy Consumption and Water Use*. • Benefits to utilities include increased operational efficiencies from improvements to IT systems resulting from preparing systems to meet Green Button requirements.	Customers, Consultants/Service Providers, Utilities	Direct, Quantified
	Reduced customer care effort	• The benefit results from a reduction in the time required to provide consumption information to utility customers.	Utilities	Indirect, Quantified
	CDM/DSM program efficiencies and innovations	• Efficiencies resulting from streamlined CDM/DSM program implementation (e.g., easier access to data to conduct audits) and program evaluation (e.g. less resource time to gain access to billing data). • Innovations to existing programs based on increased customer access to utility data.	Utilities	Indirect, Quantified

[7] Who receives the benefits

Category	Benefit	Definition	Impacted Groups[7]	Grouping
Energy Efficiency and Conservation	Energy savings from behavioural and retrofit improvements resulting from additional access to utility data	Behavioural benefits include conservation behaviours resulting from increased access to utility data, greater operational savings in commercial/industrial buildings, and increased participation in CDM/DSM programs. Examples of behavioural/ operational efficiencies include turning lights off or optimizing equipment schedules to minimize energy use. • Energy Efficiency retrofit benefits include increased implementation of energy efficiency measures (e.g. purchasing and installing energy efficient measures, conducting building audits and implementing recommendations, etc.). Measures could be implemented through participation in existing CDM/DSM programs or outside of utility programs.	Customers[8]	Indirect, Quantified

[8] Energy efficiency benefits were not applied to utilities to avoid double-counting the benefits

BENEFIT INPUTS, SOURCES AND ASSUMPTIONS

Table 8 includes key inputs for each benefit, including sources and assumptions our team used to develop them.

Benefits of increased real estate value were excluded from the analysis because the impact is diffuse and not material in the analysis: only a certain percentage of homes would be sold during the study period, of which only a certain percentage would access GB data, of which only a certain percentage would retrofit their homes to increase the value, of which a low percentage would see an increase in value because purchasers would not likely have comparable data for other homes.

Table 8. Benefit Inputs, Sources and Assumptions

Benefit Component	Unit Benefit	Assumptions/Considerations	Sources
Utility consumption, Billing and Generation Data Process Efficiencies and Ongoing Utility Consumption Monitoring and Benchmarking	**Large commercial/ industrial customers (above 10,000 sq. feet):** • $180 in avoided costs annually per building (6 hours of effort at $30/hr)	• Benefits reflect total budget impact for a portfolio of buildings as well as effort required to collect and analyze data for a single building. • The benefits were distributed among each utility type (64% electricity, 22% natural gas, 14% water), based on stakeholder input as to the type of utility from which they would receive the most Green Button-related benefits, the frequency of billing by the utilities, and the granularity of data available. • Direct benefit of implementing Green Button.	• Stakeholder consultations and interviews
	Small commercial/ industrial customers: • $198 in avoided costs annually per building	• Benefits reflect total budget impact for a portfolio of buildings as well as effort required to collect and analyze data for a single building. • Assumption that small buildings (less than 10,000 sq. feet) would experience higher benefits than larger buildings because owners of smaller buildings have less sophisticated processes to collect and manage consumption data. • A 10% increase for this benefit category was attributed to the owners of small buildings category (in comparison to the avoided costs for large buildings), based on professional judgement. • Direct benefit of implementing Green Button.	• Stakeholder consultations and interviews
	Building Owners & Residential Customers: • Annual benefit (variable based on descriptions in Assumptions column)	• Benefits vary by implementation (DMD/CMD), new vs. current users of electronic data format, customer type, and building ownership status. • Greater value to customers not currently accessing data electronically. • Direct benefit of implementing Green Button.	• Stakeholder consultations and interviews

Benefit Component	Unit Benefit	Assumptions/Considerations	Sources
Utility consumption, Billing and Generation Data Process Efficiencies and Ongoing Utility Consumption Monitoring and Benchmarking (continued)	**Consultants/service providers (cleaning and consolidating data)** • Annual benefit • 6 hours of effort at \$50/hour (1 hour for Natural Gas and Water) **Consultants/service providers (conducting audits)** • Annual benefit • \$150 (electricity only) • \$175 (electricity and Natural Gas) • \$190 (all three utility types)	• Consultants/service providers would experience easier access to data and reduced effort for data cleaning and validation. • Benefits are per building using these services. • Assume 2% of commercial building stock uses these services. • Direct benefit of implementing Green Button.	• Stakeholder consultations and interviews
CDM/DSM Program Efficiencies and Innovations	• **Large LDC:** \$10,000/year avoided costs • **Medium LDC:** \$5,000/year avoided costs • **Small LDC:** \$2,500/year avoided costs • **Large Natural Gas utility:** \$5,000/year avoided costs • **Small Natural Gas utility:** \$2,500/year avoided costs	• Most utilities reported they do not perceive the value proposition that Green Button could provide for their CDM/DSM program design and delivery models. However, they recognize it can bring some benefit to their operations (e.g. through applications that promote CDM/DSM programs or energy savings tips, through increased efficiencies for gathering consumption data for program delivery, customer negotiations, or evaluation). • The analysis therefore included a conservative estimate, based on experience evaluating CDM/DSM programs for electricity and natural gas utilities. While the estimate reflects a lack of specific data, it also reflects our understanding that the value is not zero. • No benefits were attributed to water utilities, considering their earlier stages in conservation program development compared to energy utilities. • Indirect benefit of implementing Green Button.	• Estimates based on utility interviews

Benefit Component	Unit Benefit	Assumptions/Considerations	Sources
Behaviour-Based Efficiency and Conservation	**Non-Residential Customers:** • 2% electricity and natural gas savings for participating customers (non-residential) **Residential Customers:** • 1% electricity and natural gas savings for participating customers (residential) **Water Utility Customers:** • 1% water savings for participating customers (residential and non-residential)	• Benefits allocated between utility types based on average energy consumption by sub-sector (residential, small commercial, large commercial, large industrial, and institutional). • Based on a conservative reduction of energy savings found to result from behavioural conservation programs designed around access to utility consumption data (access to data typically achieves between 4-12%). • Recognizes that savings achieved as a result of Green Button access to data may not achieve the same results as a utility-driven CDM/DSM program (utilities would not have control over all the solutions developed, quality of advice, and other factors). Behavioural-only programs typically achieve between 1 and 3%.[9] • Benefits assumed to be achieved either through existing CDM/DSM programs or outside of them (e.g. customers make the changes without receiving an incentive). The analysis does not differentiate between whether the savings are generated through utility program participation or not, as behavioural/operational benefits are assumed to require no cost/investment. • Benefits assume that utilities would have an opportunity to recruit participants to existing programs (whether or not customers take advantage of the opportunity) rather than assuming new programs will necessarily be developed that could duplicate/compete with existing savings opportunities. o This is a conservative assumption – new programs could improve the results. • New programs were excluded due to lack of information on the costs of new DSM/CDM programs based on Green Button information and because of concerns reported by electricity utilities with regards to behavioural savings and their potential contribution to Conservation First Framework 2020 savings targets. • Indirect benefit of implementing Green Button.	• Professional judgment applied to Murray, M. and J. Hawley. 2016. *Got Data? The Value of Energy Data Access to Consumers.* Mission:Data • Evaluation experience and research into behaviour-based energy savings.[8]

[9] See, for example: http://ilsagfiles.org/SAG_files/Evaluation_Documents/ComEd/ComEd_EPY7_Evaluation_Reports/ComEd_HER_Opower_PY7_Evaluation_Report_2016-02-15_Final.pdf (average of 1.15% - depending on cohort, savings range from 0.53% to 2.83% electrical savings)
http://www2.opower.com/l/17572/2013-08-22/bvhvp/17572/49284/25_ODC___Navigant_MA_Four_Year_Cross_Cutting.pdf (presents the findings of behavioural programs of Massachusetts program administrators for electricity and natural gas, which were typically around 1.5%)

Benefit Component	Unit Benefit	Assumptions/Considerations	Sources
Retrofit-Based Efficiency and Conservation	**Electricity customers:** • 10% electricity savings per building for participating customers (residential and non-residential) **Natural Gas customers:** • 4% natural gas savings per building for participating customers (residential and non-residential) **Water customers:** • 3% water savings per building for participating customers (residential and non-residential)	• Based on conservative reduction of typical energy efficiency evaluation results (not measure-specific), in which energy savings from deeper retrofits (e.g. insulation or building-envelope based) are often 20% or higher. • Savings estimated to be incremental to Conservation First Framework/Industrial Accelerator Program and DSM Framework targets. • Participation varies by sub-sector based on application of adoption curves (refer to Table 9). • We reduced utility results to account for a wide range of measures and retrofits, from simple measures such as selecting a more efficient appliance to a retrofit that improves the insulation level of the building. Therefore, overall savings would be expected to be lower than from a retrofit-only solution. • Benefits allocated between utility types based on average energy consumption by sub-sector (residential, small commercial, large commercial, large industrial, and institutional). • The analysis of retrofit benefits accounts for utility savings that occur only during the study period (5 years or 10 years, depending on the specific scenario), even though retrofit measures can produce savings over a much longer period. o This is a conservative estimate. While it reduces the potential benefits, it limits the risk of overstating the indirect benefits of Green Button and eliminates the uncertainty of the duration of those energy savings. • Benefits were assumed to be achieved either through existing CDM/DSM programs or outside of them (e.g. customers make the changes without receiving an incentive). • Indirect benefit of implementing Green Button.	• Estimates based on Ontario utility and other Canadian CDM/DSM Plans (e.g. New Brunswick and Nova Scotia) and average Ontario energy rates.

Benefit Component	Unit Benefit	Assumptions/Considerations	Sources
Reduced Utility Customer Care Efforts	• **Large LDC:** \$10,000/year avoided costs • **Medium LDC:** \$5,000/year avoided costs • **Small LDC:** \$2,500/year avoided costs • **Large Natural Gas utility:** \$5,000/year avoided costs • **Small Natural Gas utility:** \$2,500/year avoided costs	• Applied to DMD/CMD (not DMD only) since bulk of customer care is for Residential customers who are not expected to participate in a DMD-only implementation to an extent that would demonstrate impact. • Annual cost savings per utility type and size. • Green Button can support new conservation programs based on easier and more streamlined access to consumption data and can reduce cost to procure such services through a single bridge to consumers' utility data. • Direct benefit of implementing Green Button.	• Stakeholder consultations and interviews

PENETRATION LEVEL

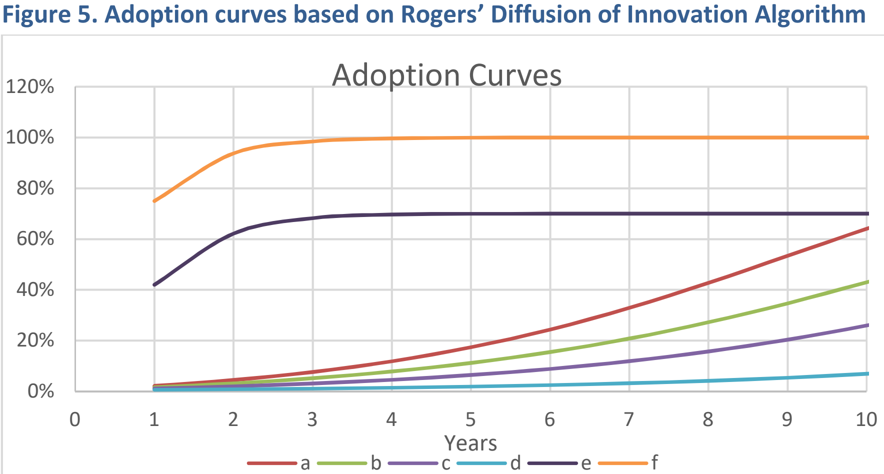
Everett Rogers, whose Diffusion of Innovation theory is used extensively in behavioural and technology-related research, identified that people will adopt new ideas or technologies at different stages, even though benefits may exist from inception. Green Button is no different: despite the benefits that increased access to utility data may have for all customers, some customers will adopt it early in the process (as was seen in the Green Button pilots), others will adopt it over time as it becomes more common and mainstream, and yet others likely never will. These trends are known as adoption curves.

The shape of adoption curves and rate of adoption however, can be different for different technologies and groups. For example, how quickly Green Button is used by a significant number or majority of customers will likely be different by customer group, depending on their individual data needs and requirements. For example, with the Large Building Energy and Water Reporting and Benchmarking initiative, we would expect large commercial, institutional, and industrial customers to adopt Green Button for data access purposes relatively sooner than a majority of residential customers.

For this reason, we developed individual adoption curves to represent the potential adoption of Green Button in the province, varying by benefit and cost category, but also by building type.

The following graph presents the different adoption curves that we applied to different groups using Rogers' Diffusion of Innovation theory, which outlines different ways in which innovations can be adopted based on the innovation itself, communications channels, time, and applicable social systems. The various curves (labelled with the letters a-f) have been applied to different stakeholder groups and benefits, as explained in Table 3 below the graph.

Figure 5. Adoption curves based on Rogers' Diffusion of Innovation Algorithm



The above penetration curves have been used for different benefits and building categories included in the model. The specific curves and rationales are outlined in Table 9 below.

Table 9. Penetration curves included in the analysis

Benefit/stakeholder	Category	Curve	Rationale
New users of utility data, owners/ managers of large and institutional facilities	Operational Efficiencies	a	Needs expressed during the consultation process were considerable; owner sophistication supports high penetration of Green Button
Retrofits to large commercial and institutional facilities	Increased conservation and energy efficiency	b	Limited to 25% of the building stock undergoing retrofits[10]
Operational benefits for large commercial and institutional facilities	Increased conservation and energy efficiency	c	Significant potential for building managers, resources available to actively manage utility consumption
Retrofits to small commercial buildings	Increased conservation and energy efficiency	c	Limited to 25% of the building stock undergoing retrofits[11]
New small commercial and residential users of utility data	Operational Efficiencies	d	Lower sophistication and availability to manage utility consumption data
Behavioural benefits for small commercial and residential buildings	Increased conservation and energy efficiency	d	Lower sophistication and availability to manage utility consumption
Retrofits to residential buildings	Increased conservation and energy efficiency	d	Limited to 25% of the building stock undergoing retrofits[12]
Large Building Energy and Water Reporting and Benchmarking (O.Reg. 20/17)	Operational Efficiencies	e	Assumes 35% would comply with regulations through means other than Green Button, such as hiring third-party consultants to capture, clean, and consolidate data (so a lower adoption curve has been selected than could be achieved from a technical perspective).
Current users of data (commercial, institutional, and industrial)	Operational Efficiencies	f	Automatic adoption of GB solution by proportion of customers accessing data as indicated by IT survey and interviews.

[10] Calculated based on common values for retrofit savings and research on additional savings (Hummer, J. and D. Brannan. 2014. *Quantifying Behavioral Spillover: The Overlooked, Uncounted Source of Program-Influenced Savings.* Behavior, Energy & Climate Change Conference.)
[11] Ibid
[12] Ibid

RESULTS OF THE ANALYSIS

As the analysis resulted in multiple iterations of very similar scenarios, this section provides an overview of the high-level results for each dimension of the analysis. In the following section, we provide the specific results of key scenarios that we believe warrant further consideration by the Ministry.

Benefit-cost ratios are provided for each result. As explained above, **if a ratio is positive, the benefits outweigh the costs of that scenario, so it is cost-effective. If it is negative, the costs exceed the benefits and the scenario is not cost-effective**. To make the consideration of such a wide range of scenarios simpler, we have colour-coded the tables: green means the combination of options (the scenario) is cost-effective; red means it is not.

GREEN BUTTON OPTIONS

The first dimension we analyzed was the consideration of Green Button implementation options: DMD only, or DMD and CMD together. The results show that, in general, a DMD/CMD implementation is more cost-effective across a range of scenarios.[13]

Table 10. Green Button DMD Scenario Cost-Benefit Results

Utility Type	Single Integrated Hosted		Multi-Integrated Hosted		Non-Integrated Hosted		In-House	
	5-year	10-year	5-year	10-year	5-year	10-year	5-year	10-year
Electricity	2.2	3.5	2.1	3.4	1.8	3.03	1.4	2.5
Electricity and Natural Gas	2.3	2.9	2.1	2.8	1.7	2.5	1.3	2.1
Electricity, Natural Gas, and Water	0.3	0.8	0.6	1.4	0.2	0.5	0.2	0.6
Natural Gas Component	2.4	1.8	2.1	1.7	1.9	1.4	0.5	0.8
Water Component	0.04	0.1	0.1	0.3	0.02	0.1	0.03	0.1

[13] The analysis was built up from a base case of electricity utilities implementing Green Button, to which natural gas utilities were added, and then water utilities. For this reason, in all results tables, the natural-gas-only and water-only components are based on incremental results (the differences in benefits and cost when the other utility types are removed), rather than on independent scenario assumptions.

Table 11. Green Button DMD/CMD Scenario Cost-Benefit Results

Utility Type	Single Integrated Hosted		Multi-Integrated Hosted		Non-Integrated Hosted		In-House	
	5-year	10-year	5-year	10-year	5-year	10-year	5-year	10-year
Electricity	4.1	3.6	4.04	3.6	3.5	3.5	3.2	3.4
Electricity and Natural Gas	4.4	3.8	4.4	3.8	3.9	3.7	3.5	3.6
Electricity, Natural Gas, and Water	1.9	2.8	1.8	2.8	1.4	2.5	1.1	2.3
Natural Gas Component	6.2	4.9	6.0	5.0	5.6	4.8	5.4	4.7
Water Component	0.5	1.1	0.5	1.04	0.3	0.8	0.3	0.7

As the tables above show, deploying Green Button Connect My Data (CMD) in conjunction with Download My Data (DMD) provides greater benefits than deploying DMD alone. While consistently formatted electronic data downloads (DMD-only) are beneficial for sophisticated customers, **the ability to develop tailor-made solutions and applications and create efficiencies with data transfer and authorization multiply the benefits** when CMD is added.

For this reason, for the remaining scenarios, we present the DMD/CMD option only.

UTILITY TYPE

As part of our analysis, we also examined whether the results changed, and to what extent, based on the type of utility to implement Green Button:

As shown in table 11 above, deploying Green Button for electricity and natural gas only is the most cost-effective option, with ratios ranging between 3.5 and 4.4 (meaning that benefits outweigh the costs by 3.5 to 4 times).

This scenario has the highest results because:

- **The benefits are greatest for electricity**: During stakeholder consultations and interviews, customers indicated they are most interested in energy efficiency and conservation for electricity and most often require data for internal reporting and benchmarking requirements. This perspective is supported by market pricing, with electricity having the highest average rate, followed by natural gas and then water.
- **The setup and integration costs for natural gas are comparatively low**: The setup and integration costs in relation to Green Button benefits are lower for natural gas utilities in comparison to electricity-only or with water utilities included because of the lower number of natural gas utilities.

While the most cost-effective option is electricity and natural gas only, **including water utilities is also cost-effective from a societal level when combined with electricity and natural gas**. However, this is primarily based on the benefits from electricity and natural gas outweighing the costs of implementing Green Button for water. In other words, implementing Green Button for water utilities in and of themselves is generally not cost-effective, because the costs outweigh the benefits when considering water on its own.[14]

Table 12. Green Button Implementation for Water Utilities Only

Option	Single Integrated Hosted		Multi-Integrated Hosted		Non-Integrated Hosted		In-House	
	5-year	10-year	5-year	10-year	5-year	10-year	5-year	10-year
DMD	0.04	0.1	0.1	0.3	0.02	0.1	0.03	0.1
DMD/CMD	0.5	1.1	0.5	1.04	0.3	0.8	0.3	0.7

This option is not cost-effective under most scenarios for the following reasons:

- **Higher integration costs**:
  - o There are a large number of metered water utilities (515), and each one would incur integration and platform development costs.
- **Lower unit benefits per customer**:
  - o Customers (excluding large customers) are generally not engaged or interested in water conservation.
  - o Water utilities generally distribute bills on a less frequent basis, so there is less opportunity for customers to use the data or receive benefits.

Water may be cost-effective on its own over a 10-year horizon with a Single Integrated Hosted or Multi-Integrated Hosted implementations; however, the result is well within the potential for error. Nevertheless, in developing our analysis, we have erred on the side of being conservative rather than permissive in terms of benefits, so this scenario should not be dismissed solely on a quantitative basis. Additional considerations may demonstrate added benefits.

IMPLEMENTATION TYPE

Implementation type refers to the type of Green Button platform scenario assessed. As highlighted above, the differences between the implementation types are the following:

[14] Only water utilities with metering infrastructure were included in the analysis. Water utilities not included in the analysis are not generally planning to upgrade their infrastructure in the next five years.

- **Single Integrated (Hosted):** One Green Button hosted Software as a Service (SaaS) platform is used by each utility type (one each for electricity, natural gas, and water utilities).
- **Multi-Integrated (Hosted):** A limited number of Green Button hosted SaaS platforms are used by all utilities.[15]
- **Non-Integrated (Hosted):** Each utility has the option to develop/procure its own Green Button SaaS hosted platform.
- **In-House:** Each utility develops its own platform on its own IT systems.

In terms of Single Integrated (Hosted) and Multi-Integrated (Hosted), the same assumptions were used to develop costs and benefits for both scenarios. However, they were applied differently: we applied the costs to three platforms for the Single Integrated Scenario (one for each utility type) and twelve platforms for the Multi-Integrated Scenario (five for electricity and water, and two for natural gas), which increased the costs for the Multi-Integrated option. The results show that the Single Integrated Hosted implementation option is the most cost-effective option when implementing for all utility types over a five-year timeframe. However, the difference is only 0.1, which is well within a margin of error due to the high-level nature of the analysis. In addition, when implementing for all utility types over a ten-year timeframe or for electricity and natural gas only, both Single Integrated and Multi-Integrated implementations are equally cost-effective.

The assumptions for both the Single Integrated and Multi-Integrated hosted implementation scenarios were identical and further refinement and granularity of results is possible. For example, these scenarios do not fully explore all the potential synergies that may exist through a single or multi-hosted solution for electricity and natural gas utilities. More in-depth research and proposals or more refined quotes from Green Button hosted solutions providers could identify additional cost savings and would also provide an opportunity to increase the accuracy of the cost component of these scenarios. Similarly, the utilities' integration costs could be further researched to increase confidence in these assumptions. For example, they could demonstrate reduced costs in a Multi-Integrated Scenario due to increased competition.

A Non-Integrated Hosted option is assumed to increase costs because of the need to develop a greater number of platforms, and In-House implementation is the least cost-effective because IT hosting is not part of utilities' core business and is therefore the least efficient in terms of costs.

[15] This was a hypothetical scenario to demonstration potential synergies in limiting the number of providers; the same assumptions were used for this scenario as for the non-integrated, with the difference being the number of platforms developed and integrated.

Table 13. Green Button Implementation Type Cost-Benefit Results

Utility Type	Single Integrated Hosted		Multi-Integrated Hosted		Non-Integrated Hosted		In-House	
	5-year	10-year	5-year	10-year	5-year	10-year	5-year	10-year
Electricity	4.1	3.6	4.04	3.6	3.5	3.5	3.2	3.4
Electricity and Natural Gas	4.4	3.8	4.4	3.8	3.9	3.7	3.5	3.6
Electricity, Natural Gas, and Water	1.9	2.8	1.8	2.8	1.4	2.5	1.1	2.3

KEY SCENARIOS

This section provides an overview of the key scenarios resulting from the analysis. In general, all scenarios included the costs and benefits assumptions included above. Specific assumptions are provided in the explanations where warranted.

As indicated earlier in this report, our analysis is designed to be conservative, so some benefits that could not be quantified with a relative degree of certainty or documentation were excluded. In addition, because of the limited data for this relatively new initiative, some proxies have been used and high-level assumptions incorporated. Therefore, we recommend interpreting the results with caution, particularly with results for which the benefit-to-cost ratio is close to 1 or in which ratios are similar but not identical. In these cases, small deviations from the assumptions used can lead to different conclusions (e.g., the benefit/cost ratio can fall or rise above 1 or be ranked differently if assumptions change).

For this reason, results from this analysis should be used to guide, not dictate, decisions. Components and considerations not included in the CBA analysis (including qualitative benefits) should also be accounted for in the decision-making process.

SCENARIO 1: SINGLE INTEGRATED/MULTI-INTEGRATED HOSTED DMD/CMD (ELECTRICITY AND NATURAL GAS ONLY)

This scenario assumes that all Ontario's electricity and natural gas utilities would implement Green Button Download My Data (DMD) and Connect My Data (CMD) for all their customers. In doing so, we assume that there is either a single hosted Software as a Service provider providing this service for all utilities (Single Integrated) or a limited number would serve the market, each with its own platform that would be shared by multiple utilities (Multi-Integrated).

The key distinction between these scenarios lies in the number of independent Green Button Platforms included in the analysis, e.g., Single Integrated (3 platforms) and Multi-Integrated (12 platforms). The difference in the number of platforms included in the analysis translates to a cost reduction for the Single Integrated scenario compared to the Multi-Integrated scenario because there are fewer platforms included in this scenario. **There are no differences in the total value of benefits estimated under these two scenarios**, since there is no evidence that the number of independent Green Button platforms would modify the nature and/or value of the benefits generated by Green Button DMD or CMD.

These scenarios are arguably the most cost-effective implementation scenarios analyzed. They capture the vast majority of potential benefits while reducing the costs required for developing and delivering Green Button solutions.

The benefit-cost ratios estimated for these scenarios are of a sufficient magnitude for us to consider them to be highly cost-effective for the province.

SCENARIO 1A: SINGLE INTEGRATED HOSTED DMD/CMD (ELECTRICITY AND NATURAL GAS UTILITIES ONLY)

This section provides an overview of the costs and benefits, in dollars, incorporated within the analysis of a **Single Integrated Green Button implementation for electricity and natural gas utilities only**.

COSTS

The following table outlines the cost categories included in the analysis.

Table 14. Scenario 1A Cost Details

Cost Category	Cost Type	5-Year Analysis ($)	10-Year Analysis ($)	Scenario-Specific Assumptions
Implementation (Utility one-time setup and integration costs)	Direct	3,920,248	3,924,558[16]	The setup cost for the Single Integrated scenario assumes one setup cost per utility type. This is a conservative estimate based on input from a SaaS provider that indicated a cost per addition of utility type.
Operational Costs[17]	Direct	771,753	2,406,040	
Retrofit Costs	Indirect	11,172,735	67,265,834	
Total		**15,864,736**	**73,596,433**	

Operational costs are significantly higher over a 10-year timeframe than over a 5-year timeframe due to increased customer participation with Green Button. Operational costs are directly related to the number of participants. Retrofit costs are significantly higher over 10 years because individuals are less likely to undertake retrofits during the initial few years of Green Button. After implementation, customers will require time to receive their data, analyze it, determine next steps, and implement changes, which delays impacts from retrofits (on both the costs and benefits side) until later in the implementation period.

BENEFITS

[16] While in reality the 5-year and 10-year one-time implementation costs would likely be identical, the analysis required a mathematical function to forecast implementation costs. The mathematical function forecasts the following rollout of Green Button through the first 5 years following enactment of the policy: 35%, 70%, 92%, 99%, 99.9%, which means that 0.1% of costs remained to be implemented after the 5-year rollout period and are reflected in the slight increase in one-time costs for the 10-year period.

[17] Sum of net-present value of annual costs over the timeframe.

The following table outlines the benefits categories included in the analysis. We note that **multiple benefits are included in each category, but to avoid double-counting overlapping benefits, they have been aggregated into these higher-level considerations**. The specific benefits included in each category are outlined in Appendix C.

Table 15. Scenario 1A Benefits Details[18]

Benefit Category	Benefit Component	Benefit Type	5-Year Analysis ($)	10-Year Analysis ($)
Operational Efficiencies	Utility Consumption, Billing and Generation Data Process Efficiencies	Direct	18,072,196	60,083,680
	Process Efficiencies (Large Building Energy and Water Reporting and Benchmarking requirements)	Direct	12,716,122	25,688,618
	Reduced Customer Care Efforts	Indirect	1,082,114	2,455,960
	CDM/DSM Program Efficiencies and Innovation	Indirect	893,384	2,027,619
Energy Efficiency and Conservation	Increased Conservation - Behavioural & Operational	Indirect	11,413,765	57,765,514
	Increased Conservation - Retrofits	Indirect	26,093,050	134,153,770
	Total		**70,270,632**	**282,175,160**

Benefits from improvement in customers' processes for accessing, cleaning, consolidating, analyzing, and reporting on their utility consumption, billing and generation data are also significantly higher over 10 years than over 5 years. During the initial period following enactment of the policy, customers with a direct interest in simplified access to building consumption data (because they already go through the process of accessing of requesting access to their consumption data in electronic format) are assumed to take advantage of Green Button features. During the next 5-year period, increased usage of Green Button is forecasted, leading to an increase in annual benefits.

Benefits resulting from retrofits are also significantly higher over 10 years than 5 for the same reasons that retrofit costs are higher: the impacts from retrofits will occur later in the period because it will take time for customers to make decisions and implement them.

RESULTS

Detailed results for the Single Integrated version of this scenario (Scenario 1A) are presented in the following tables.

[18] No scenario-specific assumptions required

Table 16. Scenario 1A Benefit-Cost Ratios

Ratio Type	5-Year Analysis	10-Year Analysis
Direct and Indirect Costs and Benefits	4.4	3.8
Direct Benefits and Costs only[19]	6.8	13.9

In this scenario, total benefits outweigh total costs by over 4 to 1 (over 5 years) or almost 4 to 1 (over 10 years). When analyzing direct benefits and costs only (excluding indirect considerations such as retrofits and program efficiencies, benefits outweigh the costs by almost 7 to 1 (over 5 years) or almost 14 to 1 (over 10 years).

Additional Results:

Table 17. Scenario 1A Energy and GHG Cumulative Impacts

Result	5-Year Analysis	10-Year Analysis
Electricity Savings	311 GWh	1741 GWh
Natural Gas Savings	1.65 PJ	8.67 PJ
GHG Reductions	168 kt CO_2e	947 kt CO_2e

To illustrate how the costs and benefits are distributed across stakeholder groups, we present the following tables.

Table 18. Scenario 1A Costs by Stakeholder Groups (5-year horizon)

Cost Component	Cost Type	Stakeholder Group			
		Electricity Utility ($)	Natural Gas Utility ($)	Customers[20] ($)	Total ($)
Implementation (One-time setup and integration costs)	Direct	3,380,494	539,754	-	**3,920,248**
Operational Costs[21]	Direct	456,696	315,057	-	**771,753**
Retrofit Costs	Indirect	-	-	11,172,735	**11,172,735**
Total		**3,837,190**	**854,811**	**11,172,735**	**15,864,736**

[19] Direct benefits and costs are a subset of total benefits and costs. However, the direct benefits and costs *ratios* are higher than the total ratios because the magnitude of benefits to costs is different for direct results than for total results.
[20] Includes all customer classes (Residential, Commercial, Industrial, and Institutional)
[21] Sum of net-present value of annual costs over the timeframe.

Table 19. Scenario 1A Benefits by Stakeholder Group (5-year horizon)

Benefit Category	Benefit Component	Benefit Type	Stakeholder Group					
			C&I ($)	Industrial ($)	Other[22] ($)	Residential ($)	Utility ($)	Total ($)
Operational Efficiencies	Customers' Utility Consumption, Billing and Generation Data Process Efficiencies	Direct	10,144,702	7,900	5,308,456	2,611,138	-	**18,072,196**
	Process Efficiencies (requirements)	Direct	12,631,762	84,360	-	-	-	**12,716,122**
	Reduced Customer Care Efforts	Indirect	-	-	-	-	1,082,114	
	CDM/DSM Program Efficiencies and Innovation	Indirect	-	-	-	-	893,384	
Energy Efficiency and Conservation	Increased Conservation - Behavioural & Operational	Indirect	9,753,339	14,529	-	1,645,898	-	**11,413,765**
	Increased Conservation - Retrofits	Indirect	20,106,940	77,336	-	5,908,773	-	**26,093,050**
	Total		**52,636,743**	**184,125**	**5,308,456**	**10,165,809**	**1,975,478**	**70,270,631**

[22] Other Stakeholders include third-party Energy Efficiency Consultants/Service Providers providing utility consumption monitoring services, energy assessments, and/or engineering services.

SCENARIO 1B: MULTI-INTEGRATED HOSTED DMD/CMD (ELECTRICITY AND NATURAL GAS UTILITIES ONLY)

The table below provides an overview of the costs and benefits, in dollars, incorporated within the analysis of a Multi-Integrated Green Button implementation for electricity and natural gas utilities only.

We note that all costs and benefits are the same as for the Single Integrated scenario except for the Implementation (one-time setup and integration) costs. This is why the scenarios are labelled 1A and 1B rather than as two different scenarios.

Table 20. Scenario 1B Cost Details

Cost Category	Cost Type	5-Year Analysis ($)	10-Year Analysis ($)	Scenario-Specific Assumptions
Implementation (One-time setup and integration costs)	Direct	4,101,232	4,105,742[23]	The setup cost for the Multi-Integrated scenario assumes: • 5 independent platforms for the electricity sector • 1 platform for the natural gas sector (because there are so few utilities) • 5 platforms for the water utilities
Operational Costs[24]	Direct	771,753	2,406,040	
Retrofit Costs	Indirect	11,172,735	67,265,834	
Total		**16,045,720**	**73,777,616**	

While most costs are approximately double when comparing the 10-year period to the 5-year period, the retrofit costs are significantly higher over 10 years because individuals are less likely to undertake retrofits during the initial few years of Green Button. After implementation, customers will require time to receive their data, analyze it, determine next steps, and implement changes, which delays impacts from retrofits (on both the costs and benefits side) until later in the implementation period.

[23] Differences between the 5-year and 10-year Implementation Costs are an artefact of the mathematical function used to forecast implementation costs. The mathematical function forecasts the following rollout of Green Button through the first 5 years following enactment of the policy: 35%, 70%, 92%, 99%, 99.9%.
[24] Sum of net-present value of annual costs over the timeframe.

Table 21. Scenario 1B Benefits Details[25]

Benefit Category	Benefit Component	Benefit Type	5-Year Analysis ($)	10-Year Analysis ($)
Operational Efficiencies	Customers' Utility Consumption, Billing and Generation Data Process Efficiencies	Direct	18,072,196	60,083,680
	Process Efficiencies (Large Building Energy and Water Reporting and Benchmarking)	Direct	12,716,122	25,688,618
	Reduced Customer Care Efforts	Indirect	1,082,114	2,455,960
	CDM/DSM Program Efficiencies and Innovation	Indirect	893,384	2,027,619
Energy Efficiency and Conservation	Increased Conservation - Behavioural & Operational	Indirect	11,413,765	57,765,514
	Increased Conservation - Retrofits	Indirect	26,093,050	134,153,770
	Total		**70,270,632**	**282,175,160**

Benefits from improvement in customers' processes for accessing, cleaning, consolidating, analyzing, and reporting on their utility consumption, billing and generation data are significantly higher over 10 years than over 5 years. During the initial period following enactment of the policy, customers with a direct interest towards simplified access to building consumption data (because they already go through the process of accessing of requesting access to their consumption data in electronic format) are assumed to take advantage of Green Button features. During the next 5-year period, increased usage of Green Button is forecasted, leading to an increase in annual benefit.

Benefits resulting from retrofits are also significantly higher over 10 years than 5 for the same reasons that retrofit costs are higher: the impacts from retrofits will occur later in the period because it will take time for customers to make decisions and implement them.

The remaining benefits are approximately double when comparing a 10-year horizon to a 5-year horizon, meaning that a relatively steady and regular pace of benefits are incurred each year.

RESULTS

Detailed results for the Multi-Integrated version of this scenario (Scenario 1B) are presented in the following tables.

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[25] No scenario-specific assumptions required

Benefit-Cost Ratios:

Table 22. Scenario 1B Benefit-Cost Ratios

Ratio Type	5-Year Analysis	10-Year Analysis
Direct and Indirect Costs and Benefits	4.4	3.8
Direct Benefits and Costs only[26]	6.8	13.6

ADDITIONAL RESULTS:

Table 23. Scenario 1B Energy and GHG Cumulative Impacts

Result	5-Year Analysis	10-Year Analysis
Electricity Savings	311 GWh	1741 GWh
Natural Gas Savings	1.65 PJ	8.67 PJ
GHG Reductions	168 kt CO_2e	947 kt CO_2e

Note that the energy and GHG impacts are identical to Scenario 1A, as the only differences between the two scenarios are in the costs; there are no differences in the benefits.

To illustrate how the costs and benefits are distributed across stakeholder groups, we present the following tables.

Table 24. Scenario 1B Costs by Stakeholder Group (5-year horizon)

Cost Category	Cost Type	Stakeholder Group			
		Electricity Utility ($)	Natural Gas Utility ($)	Customers[27] ($)	Total ($)
Implementation (One-time setup and integration costs)	Direct	3,561,478	539,754	-	**4,101,232**
Operational Costs[28]	Direct	456,696	315,056	-	**771,752**
Retrofit Costs	Indirect	-	-	11,172,735	**11,172,735**
Total		**4,018,174**	**854,810.5**	**11,172,735**	**16,045,720**

[26] Direct benefits and costs are a subset of total benefits and costs. However, the direct benefits and costs *ratios* are higher than the total ratios because the magnitude of benefits to costs is different for direct results than for total results.
[27] Includes all customer classes (Residential, Commercial, Industrial, and Institutional)
[28] Sum of net-present value of annual costs over the timeframe.

Table 25. Scenario 1B Benefits by Stakeholder Group (5-year horizon)

Benefit Category	Benefit Component	Benefit Type	Stakeholder Group					
			C&I ($)	Industrial ($)	Other[29] ($)	Residential ($)	Utility ($)	Total ($)
Operational Efficiencies	Customers' Utility Consumption, Billing and Generation Data Process Efficiencies	Direct	10,144,702	7,900	5,308,456	2,611,138	-	**18,072,196**
	Process Efficiencies (requirements)	Direct	12,631,762	84,360	-	-	-	**12,716,122**
	Reduced Customer Care Efforts	Indirect	-	-	-	-	1,082,114	**1,082,114**
	CDM/DSM Program Efficiencies and Innovation	Indirect	-	-	-	-	893,384	**893,384**
Energy Efficiency and Conservation	Increased Conservation - Behavioural & Operational	Indirect	9,753,339	14,529	-	1,645,898	-	**11,413,765**
	Increased Conservation - Retrofits	Indirect	20,106,940	77,336	-	5,908,773	-	**26,093,050**
	Total		**52,636,743**	**184,125**	**5,308,456**	**10,165,809**	**1,975,498**	**70,270,632**

[29] Other Stakeholders include third-party Energy Efficiency Consultants/Service Providers providing utility consumption monitoring services, energy assessments, and/or engineering services.

SCENARIO 2: SINGLE INTEGRATED/MULTI-INTEGRATED HOSTED DMD/CMD: ELECTRICITY, NATURAL GAS AND WATER

The second key scenario assumes that all of Ontario's metered electricity, natural gas and water utilities would implement Green Button Download My Data (DMD) and Connect My Data (CMD) for all their customers. The implementation could occur with either a single hosted Software as a Service provider providing the service for all utilities (Single Integrated) or a small group of Software as a Service providers serving the market through a limited number of platforms shared by multiple utilities (Multi-Integrated).

As with Scenario 1A and 1B (for Electricity and Natural Gas utilities only), the key distinction between these scenarios lies in the number of independent Green Button Platforms included in the analysis (i.e., Single Integrated (3) and Multi-Integrated (12). The difference in the number of platforms included in the analysis translates to a cost reduction for the Single Integrated Scenario compared to the Multi-Integrated scenario. On the benefits side, there are no differences between the two, as there is no evidence that the number of independent Green Button platforms would modify the nature and/or value of the benefits generated by Green Button CMD.

The benefit-cost ratios for these scenarios indicate they are cost-effective, albeit to a lesser extent than the electricity and natural gas-only scenarios. The lower benefit-to-cost ratio is primarily driven by:

- Higher setup and integration costs required by the large number of water utilities in the province (because each utility requires its own setup costs).
- A lower benefit for water utility customers than for electricity and natural gas customers relating to conservation and access to billing and generation data. Specifically, customers consider access to their water consumption and billing data to be of less value than access to their electricity and natural gas data, and they are less concerned about conservation opportunities. This lower level of concern results in fewer benefits when Green Button is implemented for water utilities.

These two factors considerably reduce the value proposition of this scenario from a purely numbers-based perspective. As noted above, however, additional considerations not included in the quantitative analysis may be equally important and should inform part of the Ministry's policy.

Additional synergies that reduce set-up and integration costs could have a profound impact on the result of this analysis, considering they would apply to a much higher number of utilities. For example, if only the largest water utilities were included in the implementation (the 37 largest utilities serve approximately 78% of Ontario's population), it would reduce the number of implementations drastically. Another example would be to set up a water-focused task force to explore options that reduce integration costs for small utilities.

SCENARIO 2A: SINGLE INTEGRATED HOSTED DMD/CMD (ALL UTILITY TYPES)

The table below provides an overview of the costs and benefits, in dollars, incorporated within the analysis of a Single Integrated Green Button implementation for all utility types.

Table 26. Scenario 2A Cost Details

Cost Category	5-Year Analysis ($)	10-Year Analysis ($)	Scenario-Specific Assumptions
Implementation (One-time setup and integration costs)	30,408,975	30,442,411	The setup cost for the Single Integrated scenario assumes one setup cost per utility type. This is based on input from a SaaS provider that indicated a cost per addition of utility type and was selected to provide a conservative estimate.
Operational Costs[30]	1,225,917	3,822,160	
Retrofit Costs	13,290,836	79,923,128	
Total	**44,925,728**	**114,187,699**	

As indicated above, implementation and operational costs are significantly higher because of the number of water utilities: 590 utilities are included in this scenario (of which 515 are water utilities), compared with 75 in Scenarios 1A and 1B. The number of utilities translates into a multiplication of these costs.

10-year costs are significantly higher than 5-year costs for the same reasons as Scenarios 1A and 1B: individuals are less likely to undertake retrofits during the initial few years of Green Button. After implementation, customers will require time to receive their data, analyze it, determine next steps, and implement changes, which delays impacts from retrofits (on both the costs and benefits side) until later in the implementation period.

[30] Sum of net-present value of annual costs over the timeframe.

Table 27. Scenario 2A Benefits Details[31]

Benefit Category	Benefit Component	Benefit Type	5-Year Analysis ($)	10-Year Analysis ($)
Operational Efficiencies	Customers' Utility Consumption, Billing and Generation Data Process Efficiencies	Direct	25,228,276	78,289,889
	Process Efficiencies (Large Building Energy and Water Reporting and Benchmarking)	Direct	14,835,476	29,970,054
	Reduced Customer Care Efforts	Indirect	1,639,242	3,720,413
	CDM/DSM Program Efficiencies and Innovation	Indirect	1,712,222	4,609,824
Energy Efficiency and Conservation	Increased Conservation - Behavioural & Operational	Indirect	14,071,675	71,530,678
	Increased Conservation - Retrofits	Indirect	26,802,103	137,226,936
	Total		**84,288,994**	**325,347,793**

Benefits from improvement in customers' processes for accessing, cleaning, consolidating, analyzing, and reporting on their utility consumption, billing and generation data are significantly higher over 10 years than over 5 years. During the initial period following enactment of the policy, customers with a direct interest towards simplified access to building consumption data (because they already go through the process of accessing of requesting access to their consumption data in electronic format) are assumed to take advantage of Green Button features. During the next 5-year period, increased usage of Green Button is forecasted, leading to an increase in annual benefit.

Benefits from increased conservation (retrofits and behavioural) are only marginally larger in this scenario than in Scenarios 1A and 1B because our research indicated that water conservation is not a primary concern for customers, who are more likely to invest in electricity and natural gas conservation.

RESULTS

Detailed results for the Single Integrated version of this scenario (Scenario 1B) are presented in the following tables.

[31] No scenario-specific assumptions required

Table 28. Scenario 2A Benefit-Cost Ratios

Ratio Type	5-Year Analysis	10-Year Analysis
Direct and Indirect Costs and Benefits	1.9	2.8
Direct Benefits and Costs only[32]	1.3	3.3

Scenario 2A, in which water utilities have been added to the analysis for a Single Integrated Hosted solution of both DMD and CMD, is cost effective when considering total costs and benefits.

While the analysis shows that considering direct costs and benefits only (i.e., excluding actions that are only indirectly resulting from a Green Button implementation, such as energy efficiency and conservation retrofits) is also cost-effective, the 5-year analysis is close enough to 1 (i.e., the benefits do not substantially outweigh the costs) that we cannot be confident in that particular result, since the data inputs and considerations are not granular enough to assume results close to 1 are definitely cost-effective.

However, we note that the analysis was designed to be conservative, in that we intentionally used mid-to-low range estimates of benefits, and mid-to-high ranges of costs, in order to provide as rigorous an analysis as possible within the scope of the work.

ADDITIONAL RESULTS:

Table 29. Scenario 2A Energy and GHG Cumulative Impacts

Result	5-Year Analysis	10-Year Analysis
Electricity Savings	311 GWh	1741 GWh
Natural Gas Savings	1.65 PJ	8.67 PJ
Water	1,567,203 m^3	8,466,860 m^3
GHG Reductions	168 kt CO_2e	947 kt CO_2e

To illustrate how the costs and benefits are distributed across stakeholder groups, we present the following tables.

[32] Direct benefits and costs are a subset of total benefits and costs. However, the direct benefits and costs *ratios* are higher than the total ratios because the magnitude of benefits to costs is different for direct results than for total results.

Table 30. Scenario 2A Costs by Stakeholder Group (5-year horizon)

Cost Category	Cost Type	Stakeholder Group				
		Electricity Utility ($)	Natural Gas Utility ($)	Water Utility ($)	Customers ($)	Total ($)
Implementation (One-time setup and integration costs)	Direct	3,380,494	539,754	26,488,727	-	**30,408,975**
Operational Costs[33]	Direct	456,696	315,057	454,164	-	**1,225,917**
Retrofit Costs	Indirect	-	-	-	13,290,836	**13,290,836**
Total		**3,837,190**	**854,811**	**26,942,892**	**13,290,836**	**44,925,729**

Table 31. Scenario 2A Benefits by Stakeholder Group (5-year horizon)

Benefit Category	Benefit Component	Benefit Type	Stakeholder Group					
			C&I ($)	Industrial ($)	Other[34] ($)	Residential ($)	Utility ($)	Total ($)
Operational Efficiencies	Customers' Utility Consumption, Billing and Generation Data Process Efficiencies	Direct	12,285,408	9,875	10,038,462	2,894,531	-	**25,228,276**
	Process Efficiencies	Direct	14,737,056	98,420	-	-	-	**14,835,476**
	Reduced Customer Care Efforts	Indirect	-	-	-	-	1,639,242	**1,639,242**
	CDM/DSM Program Efficiencies and Innovation	Indirect	-	-	-	-	1,712,222	**1,712,222**
Energy Efficiency and Conservation	Increased Conservation - Behavioural & Operational	Indirect	12,407,375	18,403	-	1,645,898	-	**14,071,675**
	Increased Conservation - Retrofits	Indirect	20,106,940	77,336	-	6,617,826	-	**26,802,103**
	Total		**59,536,779**	**204,035**	**10,038,462**	**11,158,255**	**3,351,464**	**84,288,994**

[33] Sum of net-present value of annual costs over the timeframe.
[34] Other Stakeholders include third-party Energy Efficiency Consultants/Service Providers providing utility consumption monitoring services, energy assessments, and/or engineering services.

SCENARIO 2B: MULTI-INTEGRATED HOSTED DMD/CMD (ALL UTILITY TYPES)

The table below provides an overview of the costs and benefits, in dollars, incorporated within the analysis of a Multi-Integrated Green Button implementation for electricity and natural gas utilities only.

Table 32. Scenario 2B Cost Details

Cost Category	Cost Type	5-Year Analysis ($)	10-Year Analysis ($)	Scenario-Specific Assumptions
Implementation (One-time setup and integration costs)	Direct	31,338,419	31,372,876	The setup cost for the Multi-Integrated scenario assumes: • 5 independent platforms for the electricity sector • 1 platform for the natural gas sector (because there are so few utilities) • 5 platforms for the water utilities
Operational Costs[35]	Direct	1,225,917	3,822,160	
Retrofit Costs	Indirect	13,290,836	79,923,128	
Total		**45,855,172**	**115,118,164**	

The costs are the same in this scenario as for the Single Integrated (All Utilities) scenario except for the Implementation (one-time setup and integration) costs. This is because the only assumptions that changed for the Multi-Integrated Scenario were the number of platforms (12 compared to 3), which then increased the platform setup and integration costs. All other assumptions remain the same. This is why the scenarios are labelled 2A and 2B rather than as two different scenarios.

[35] Sum of net-present value of annual costs over the timeframe.

Table 33. Scenario 2B Benefits Details[36]

Benefit Category	Benefit Component	Benefit Type	5-Year Analysis ($)	10-Year Analysis ($)
Operational Efficiencies	Customers' Utility Consumption, Billing and Generation Data Process Efficiencies	Direct	25,228,276	78,289,889
	Process Efficiencies	Direct	14,835,476	29,970,054
	Reduced Customer Care Efforts	Indirect	1,639,242	3,720,413
	CDM/DSM Program Efficiencies and Innovation	Indirect	1,712,222	4,609,824
Energy Efficiency and Conservation	Increased Conservation - Behavioural & Operational	Indirect	14,071,675	71,530,678
	Increased Conservation - Retrofits	Indirect	26,802,103	137,226,936
	Total		**84,288,994**	**325,347,793**

The benefits for this Scenario are identical to those in the Single Integrated (All Utilities) Scenario, as our research indicated the benefits would not differ based on the number of platforms implemented.

RESULTS

Detailed results for the Multi-Integrated version of this scenario (Scenario 2B) are presented in the following tables.

Table 34. Scenario 2B Benefit-Cost Ratios

Ratio Type	5-Year Analysis	10-Year Analysis
Total	1.8	2.8
Direct Benefits and Costs only[37]	1.3	3.3

The results for this scenario are identical to the results for the Single Integrated scenario (2A) because the difference between the two are only related to the costs for developing 12 platforms (for Multi-Integrated) rather than 5 platforms (for Single Integrated). These costs are minimal compared to the overall costs, so the difference is eliminated through rounding the numbers to one decimal place. In other words, it is insignificant.

[36] No scenario-specific assumptions required

[37] Direct benefits and costs are a subset of total benefits and costs. However, the direct benefits and costs *ratios* are higher than the total ratios because the magnitude of benefits to costs is different for direct results than for total results.

ADDITIONAL RESULTS:

Table 35. Scenario 2B Energy and GHG Cumulative Impacts

Result	5-Year Analysis	10-Year Analysis
Electricity Savings	311 GWh	1741 GWh
Natural Gas Savings	1.65 PJ	8.67 PJ
Water	1,567,203 m^3	8,466,860 m^3
GHG Reductions	168 kt CO_2e	947 kt CO_2e

To illustrate how the costs and benefits are distributed across stakeholder groups, we present the following tables.

Table 36. Scenario 2B Costs by Stakeholder Group (5-year horizon)

Cost Category	Cost Type	Stakeholder Group				
		Electricity Utility ($)	Natural Gas Utility ($)	Water Utility ($)	Customers ($)	Total ($)
Implementation (One-time setup and integration costs)	Direct	3,561,478	539,754	27,237,186	-	**31,338,419**
Operational Costs[38]	Direct	456,696	315,057	454,164	-	**1,225,917**
Retrofit Costs	Indirect	-	-	-	13,290,836	**13,290,836**
Total		**4,018,174**	**854,811**	**27,691,351**	**13,290,836**	**45,855,172**

[38] Sum of net-present value of annual costs over the timeframe.

Table 37. Scenario 2B Benefits by Stakeholder Group (5-year horizon)

Benefit Category	Benefit Component	Benefit Type	Stakeholder Group					
			C&I ($)	Industrial ($)	Other ($)	Residential ($)	Utility ($)	Total ($)
Operational Efficiencies	Customers’ Utility Consumption, Billing and Generation Data Process Efficiencies	Direct	12,285,408	9,875	10,038,462	2,894,531	-	**25,228,276**
	Process Efficiencies	Direct	14,737,056	98,420	-	-	-	**14,835,476**
	Reduced Customer Care Efforts	Indirect	-	-	-	-	1,639,242	**1,639,242**
	CDM/DSM Program Efficiencies and Innovation	Indirect	-	-	-	-	1,712,222	**1,712,222**
Energy Efficiency and Conservation	Increased Conservation - Behavioural & Operational	Indirect	12,407,375	18,403	-	1,645,898	-	**14,071,675**
	Increased Conservation - Retrofits	Indirect	20,106,940	77,336	-	6,617,826	-	**26,802,103**
	Total		**59,536,779**	**204,035**	**10,038,462**	**11,158,255**	**3,351,464**	**84,288,994**

DIRECT AND INDIRECT COSTS

The tables on the following pages provide an overview of the total costs (in dollars) by key scenario, over five- and ten-year timeframes as well as subsequent breakouts of direct and indirect costs.

We note that these costs are high level and used to generate comparisons between potential scenarios; they are not implementation-level cost estimates.

FIVE-YEAR HORIZON

Table 38. Total Benefits and Costs, Combining Direct and Indirect (5-year horizon)

5 Years	Single Integrated Hosted		Multi-Integrated Hosted		Non-Integrated Hosted		In-House	
	Benefits	Costs	Benefits	Costs	Benefits	Costs	Benefits	Costs
Electricity	$54,348,157	$13,239,659	$54,348,157	$13,420,643	$54,348,157	$15,353,563	$54,348,157	$17,153,013
Electricity and Natural Gas	$70,270,632	$15,864,736	$70, 270,632	$16,045,720	$70, 270,632	$18,255,315	$70, 270,632	$20,133,528
Electricity, Natural Gas, and Water	$84,288,994	$44,925,729	$84, 288,994	$45,855,172	$84, 288,994	$59,527,055	$84, 288,994	$73,435,858

Table 39. Breakout of Direct and Indirect Benefits and Costs, Single- and Multi-Integrated (5-year horizon)

5 Years	Single Integrated Hosted				Multi-Integrated Hosted			
	Benefits		Costs		Benefits		Costs	
	Direct	Indirect	Direct	Indirect	Direct	Indirect	Direct	Indirect
Electricity	$24,638,139	$29,710,018	$3,837,190	$9,402,468	$24,638,139	$29,710,018	$4,018,174	$9,402,468
Electricity and Natural Gas	$31,903,633	$38,366,999	$4,692,001	$11,172,735	$31,903,633	$38,366,999	$4,872,985	$11,172,735
Electricity, Natural Gas, and Water	$42,555,032	$41,733,962	$31,634,892	$13,290,836	$42,555,032	$41,733,962	$32,564,336	$13,290,836

Table 40. Breakout of Direct and Indirect Benefits and Costs, Non-Integrated and In-House (5-year horizon)

5 Years	Non-Integrated Hosted				In-House			
	Benefits		Costs		Benefits		Costs	
	Direct	Indirect	Direct	Indirect	Direct	Indirect	Direct	Indirect
Electricity	$24,638,139	$29,710,018	$5,951,095	$9,402,468	$24,638,139	$29,710,018	$7,750,544	$9,402,468
Electricity and Natural Gas	$31,903,633	$38,366,999	$7,082,579	$11,172,735	$31,903,633	$38,366,999	$8,960,793	$11,172,735
Electricity, Natural Gas, and Water	$42,555,032	$41,733,962	$46,236,219	$13,290,836	$42,555,032	$41,733,962	$60,145,022	$13,290,836

TEN-YEAR HORIZON

Table 41. Total Benefits and Costs, Combining Direct and Indirect (10-year horizon)

10 Years	Single Integrated Hosted		Multi-Integrated Hosted		Non-Integrated Hosted		In-House	
	Benefits	Costs	Benefits	Costs	Benefits	Costs	Benefits	Costs
Electricity	$220,141,043	$60,938,670	$220,141,043	$61,119,853	$220,141,043	$63,155,925	$220,141,043	$65,199,079
Electricity and Natural Gas	$282,267,635	$73,635,939	$282,267,635	$73,777,616	$282,267,635	$76,187,875	$282,267,635	$78,477,384
Electricity, Natural Gas, and Water	$325,440,269	$114,227,205	$325,440,269	$115,118,165	$325,440,269	$129,204,994	$325,440,269	$143,778,684

Table 42. Breakout of Direct and Indirect Benefits and Costs, Single and Multi-Integrated (10-year horizon)

10 Years	Single Integrated Hosted				Multi-Integrated Hosted			
	Benefits		Costs		Benefits		Costs	
	Direct	Indirect	Direct	Indirect	Direct	Indirect	Direct	Indirect
Electricity	$68,380,297	$151,760,747	$4,808,314	$56,130,356	$68,380,297	$151,760,747	$4,989,497	$56,130,356
Electricity and Natural Gas	$88,303,608	$193,871,551	$6,330,599	$67,265,834	$88,303,608	$193,871,551	$6,511,782	$67,265,834
Electricity, Natural Gas, and Water	$114,637,912	$210,709,882	$34,264,571	$79,923,128	$114,637,912	$210,709,882	$35,195,036	$79,923,128

Table 43. Breakout of Direct and Indirect Benefits and Costs, Non-Integrated and In-House (10-year horizon)

10 Years	Non-Integrated Hosted				In-House			
	Benefits		Costs		Benefits		Costs	
	Direct	Indirect	Direct	Indirect	Direct	Indirect	Direct	Indirect
Electricity	$68,380,297	$151,760,747	$7,166,269	$56,130,356	$68,380,297	$151,760,747	$9,209,423	$56,130,356
Electricity and Natural Gas	$88,303,608	$193,871,551	$9,132,166	$67,265,834	$88,303,608	$193,871,551	$11,420,804	$67,265,834
Electricity, Natural Gas, and Water	$114,637,912	$210,709,882	$49,530,676	$79,923,128	$114,637,912	$210,709,882	$64,103,496	$79,923,128

QUALITATIVE BENEFITS

In addition to the purely numerical analysis presented above, Green Button provides additional benefits to customers, utilities and the Government. Benefits that were minimal, could not be quantified or estimated due to a lack of data, or could not be robustly or clearly attributed to Green Button were excluded from the analysis presented above. However, this does not mean they are not important considerations.

We recommend the Ministry's use the quantitative analysis provided above to inform its proposal. However, the proposal should not be limited to this assessment; qualitative benefits should also be considered. The following are benefits related to Green Button that were confirmed by our research but were not included in the quantitative analysis for the reasons explained above:

- **Increased energy efficiency awareness/education:** Customers benefit from increased awareness about energy efficiency and utilities benefit from opportunities to educate their customers through Green Button applications. While some of these benefits are quantified through increased conservation efforts resulting from access to data, our research indicates additional opportunities exist that would result in higher benefits were they able to be quantified or confirmed.

- **Increased real estate value:** Access to data about utility costs for buildings (homes and commercial buildings) can increase real estate value when these buildings are for sale. However, this value tends to increase over time, as the market becomes attuned to looking for, and basing decisions on, this type of information. For this reason, the benefits would not be material in the early years. In addition, they would not be material because they would be a subset (of buildings sold on the market) of a subset (of buildings that had retrofits resulting from Green Button). In addition, while initiatives such as Home Energy Rating and Disclosure are being examined and planned in Ontario, without an immediate launch, owners will not be required to provide this information, leading to even lower potential benefits due to lack of consistency until programs launch. For this reason, we were not able to estimate the impacts, and we expect them to be minimal in the early years. However, over time, we suggest these benefits will play a larger role in overall Green Button benefits.

- **Increased customer satisfaction:** While increased customer satisfaction as a result of customers understanding their utility consumption and changes to bills can be quantified in terms of survey scale results, it is difficult to convert this satisfaction to dollars saved on the part of utilities. There is not an automatic, direct link between customer satisfaction and reduced customer care centre calls, for example. Therefore, we were not able to include this benefit in the quantified analysis. Nevertheless, it can be an important benefit to utilities at a qualitative level.

- **Innovation in CDM/DSM programs:** Future CDM/DSM programs being developed as a result of Green Button Connect My Data, including to assist with Pay-for-Performance program design, are a very real possibility of a province-wide implementation of Green Button. We therefore included a token amount as an indirect benefit; however, it is not significant and not to the extent that could be expected for the following reasons:

- We did not have enough data to suggest the magnitude of such programs (either in terms of costs or savings).
- Concerned about the risk of relying on behavioural change to achieve their 2020 targets, electricity utilities were clear they were not specifically planning to design these programs in the near future.
- There is the potential for evaluation efficiencies related to easier, real-time access to consistent, machine-readable data; however, while utilities admitted this potential existed, they could not see how it could be executed.

We therefore believe there are benefits of CDM/DSM program innovation resulting from Green Button, but we were not able to quantify them to a great extent in the analysis.

- **Supporting government policy objectives:** An important benefit of Green Button is its ability to support government policy objectives, including helping to reduce fossil fuel emissions from enhanced customer access to utility data (as stated in Ontario's Climate Change Action Plan). Another example is the Minister's directive to the Ontario Energy Board to provide guidance and expectations to utilities within three parameters, one of which is customer control (defined as "providing the customer with increased information and tools to promote conservation of electricity".[39] The Board highlights Green Button as an example for utilities to provide consumption data to their customers in a user-friendly format in order to achieve customer control objectives. Green Button is able to support these, and other similar objectives. However, the quantified dollar value cannot be estimated and is therefore addressed qualitatively only.

- **Economic development and innovation (i.e., improved access to North American market, supporting development of innovative services):** Third-party solution providers/application developers indicated that a province-wide implementation of Green Button would provide them with an important opportunity to develop applications that could be used in a broader North American market and support the development of innovative services. In addition, customer access to data could result in job creation and positive economic impact in Ontario (through increased demand for consultant/service provider services, greater efficiencies in existing organizations, etc.). While some of these benefits can be quantified, to do so requires a great number of assumptions that we believed would reduce the robustness and validity of the outputs. We therefore elected to exclude them from the model and address them qualitatively.

[39] Ontario Energy Board. 2013. *Supplemental Report on Smart Grid.* EB-2011-0004. February 11, 2013.

CONCLUSION

Dunsky's cost-benefit analysis of mandating Green Button in Ontario, conducted for Ontario's Ministry of Energy, was designed to assess the cost-effectiveness of implementing Green Button across a range of scenarios, with variables focused on:

- **Green Button Options:** DMD only or DMD/CMD;
- **Utility Type:** Electricity, Natural Gas, Water; and
- **Implementation Type:** Single Integrated (Hosted), Multi-Integrated (Hosted), Non-Integrated (Hosted), In-House.

To develop inputs and obtain feedback on the results of the analysis, we consulted a broad range of stakeholders, including utilities, customers, government and intra-sector organizations, third-party service providers, and non-profit groups and associations.

The results of our analysis indicate that implementing Green Button in Ontario will be cost-effective from a societal standpoint. When focusing purely on the numbers, **implementing Green Button DMD/CMD across electricity and natural gas utilities is the most cost-effective path forward**.

Adding water utilities to the implementation is also a cost-effective scenario from a societal standpoint under a single-integrated or multi-integrated model. However, this is primarily based on the benefits from electricity and natural gas outweighing the costs of implementing Green Button for water. In other words, implementing Green Button for water utilities in and of themselves is generally not cost-effective, because the costs outweigh the benefits when considering water on its own.

In addition, implementing Green Button Connect My Data (CMD) in conjunction with Download My Data (DMD) provides the greatest benefits, and a single-integrated or multi-integrated implementation (with one, or a limited number of Green Button platforms for each utility type) is the most cost-effective implementation type, with negligible differences in results between the two.

We note that our analysis was high-level and designed to assess whether or not benefits outweighed the costs of a Green Button implementation. It does not contain enough granularity to assess actual implementation costs. Qualitative considerations such as such as increases in awareness of energy efficiency, real estate value, customer satisfaction, and CDM/DSM program innovation, and economic development and innovation, as well as support for government policy objectives would also increase the value of a Green Button implementation. They have not, however, been included within the quantitative analysis. For these reasons, any of the scenarios included in this report should be considered valid outputs to assist the Ministry in moving forward with a proposal for a Green Button implementation in Ontario.

APPENDIX A: COST-BENEFIT ANALYSIS RESULTS STAKEHOLDER PRESENTATION

ONTARIO GREEN BUTTON COST-BENEFIT ANALYSIS
Results

JULY 2016

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ENERGY CONSULTING

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DUNSKY: OVERVIEW

CLIENTS (partial list)

EXPERTISE

- Energy efficiency and demand-side management
- Renewable energy and emerging technologies
- Greenhouse gas reductions

SERVICES

- Design and evaluation of programs, plans and policies
- Strategic and regulatory support
- Technical support and analysis

CLIENTELE

- Utilities
- Governments
- Solution Providers
- Large consumers
- Non-profits

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OVERVIEW

- Objective:
  - Assess the impacts of implementing Green Button in Ontario across a range of potential scenarios to help inform the Ministry of Energy's Green Button proposal.

March/ April
- Stakeholder consultations (focus groups) to introduce Green Button and to understand stakeholder data requirements and areas of benefits.

April/ May
- Interviews with identified stakeholders to gather information on costs and benefits related to Green Button implementation.

June
- Surveyed utilities and hosted Software as a Service (SaaS) Green Button implementation providers to help quantify costs and benefits.
- Additional secondary research to develop assumptions and gather data for additional costs and benefits.

Cost-Benefit Analysis Methodology

1. Stakeholder Consultations
2. Primary and Secondary Research
3. Inputs and Assumptions
4. Implementation Scenarios
4. Scenario Analysis

COSTS & BENEFITS – CATEGORIZATION

QUANTITATIVE		QUALITATIVE
Direct (Layer 1A)	Indirect (Layer 2A)	(Layer 2B)
• Benefits and costs are a direct result of Green Button implementation • Monetary value can be estimated based on available information	• Indirect consequence of Green Button implementation • Require an additional external influence or decision point in order to materialize • Monetary value can be estimated based on available information	• Not included in Cost-Benefit Model • Reported as “additional costs/ benefits” • Used in overall analysis and policy recommendations

COSTS AND BENEFITS

- Quantitative categories included in the cost-benefit analysis are presented below.
- The analysis is conservative.
  - Benefits that were minimal, could not be quantified or estimated, or could not be attributed clearly to Green Button were excluded or included in the qualitative benefits.

	Item	Impacted Groups*	Category
Costs	• Implementation – one-time set-up costs (platform development and utility integration)	Hosted SaaS GB Implementation Providers, Utilities	Direct, Quantified
	• Operational - annual	Utilities	Direct, Quantified
	• Energy efficiency retrofits	Customers	Indirect, Quantified
Benefits (Quantified)	• Resource and time efficiencies due to simplified process and standard format related to accessing data (i.e., for internal or external monitoring, or benchmarking requirements) • Included for customers/service providers currently monitoring and benchmarking, and for new customer requirements resulting from Bill 135	Customers, Service Providers	Direct, Quantified
	• Increased energy efficiency and conservation (behavioural, operational, retrofit), both within and outside of existing CDM/DSM programs	Customers**	Indirect, Quantified
	• Reduced customer care effort	Utilities	Indirect, Quantified
	• CDM/DSM program efficiencies and innovations	Utilities	Indirect, Quantified

*Groups to which costs and benefits are assigned.
**Benefits are assigned to end-users only (not utilities) to avoid double-counting.

COSTS AND BENEFITS

- Qualitative categories are presented below but were not included in the cost-benefit analysis calculations.

	Item	Impacted Groups*	Category
Benefits (Not Quantified)	Increased energy efficiency awareness/education	Customers, Utilities	Direct, Qualitative
	Increased real estate value	Customers	Direct, Qualitative
	Increased customer satisfaction	Utilities	Direct, Qualitative
	Innovation in CDM/DSM programs	Utilities	Direct, Qualitative
	Supporting government policy objectives	Utilities, Government	Direct, Qualitative
	Economic development and innovation (i.e., improved access to North American market, supporting development of innovative services)	Service Providers, Government	Direct, Qualitative

*Groups to which costs and benefits are assigned.

KEY DRIVERS - COSTS

- Setup Costs
  - Setup costs are mostly influenced by the utility's integration services.*
  - For utility types with a significant number of individual utilities (e.g., water and electricity), the number of independent platforms represent a significant portion of the costs.
- Annual Costs
  - Ongoing annual costs are influenced mostly by the penetration of Green Button in Ontario.
  - Directly related to activity level on the platform.

*i.e., integration with customer portals, Extract, Transform, Load (ETL) systems, meter data, MDM/R; testing; marketing; security and privacy validation.

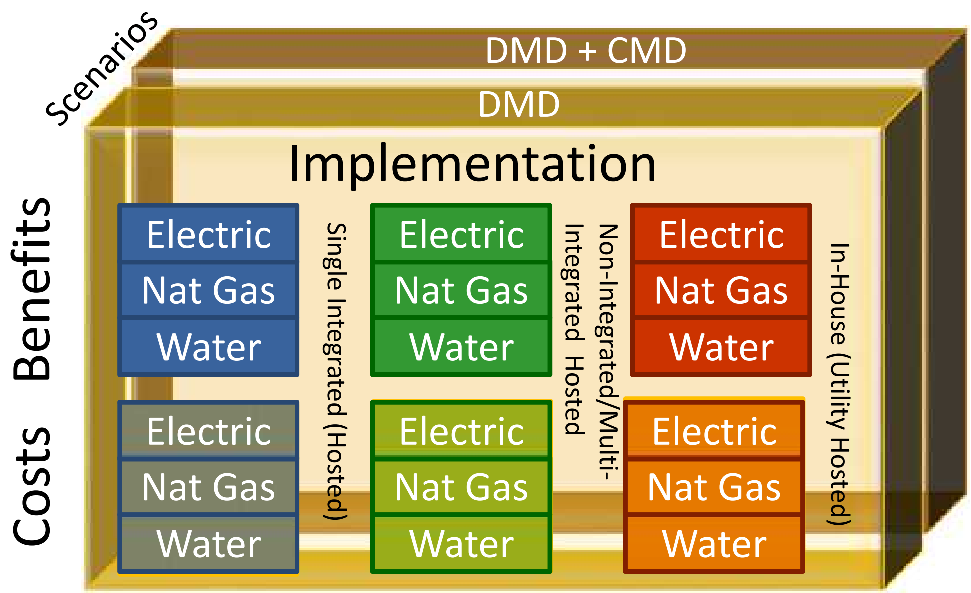
KEY DRIVERS - BENEFITS

- Benefits – ~85% in Commercial and Institutional (C&I) Sector

1. Increased Conservation – Energy Efficiency (EE) Retrofit and Behavioural (indirect benefit from Green Button)
    - *Green Button provides customers with more timely and easier access to data so they are more likely to undertake EE actions*
    - *Greatest benefits are in C&I EE Retrofit*
    - *2nd greatest benefits are in C&I Behavioural and Operational*
2. Future Large Building Energy and Water Reporting and Benchmarking requirements (Bill 135) (indirect benefit from Green Button)
    - *~18,000 buildings are expected to be required to annually report monthly energy and water consumption*
    - *Green Button provides a simplified process to collect this information*
3. Increased Efficiencies in Consumption, Billing and Generation Data Processes – replace existing processes (direct benefit from Green Button)
    - *Reduced efforts to collect and process utility consumption data*
    - *Reduced efforts to collect and process utility bills*
    - *Reduced efforts for data validation and quality control*

SCENARIOS

- 3 Dimensions
  - **Utility Type:** Electric, Natural Gas, Water
  - **Implementation Type:** Single Integrated (Hosted), Multi-Integrated/Non-Integrated (Hosted), In-House
  - **Green Button Option:** DMD, DMD+CMD



Green Button Option

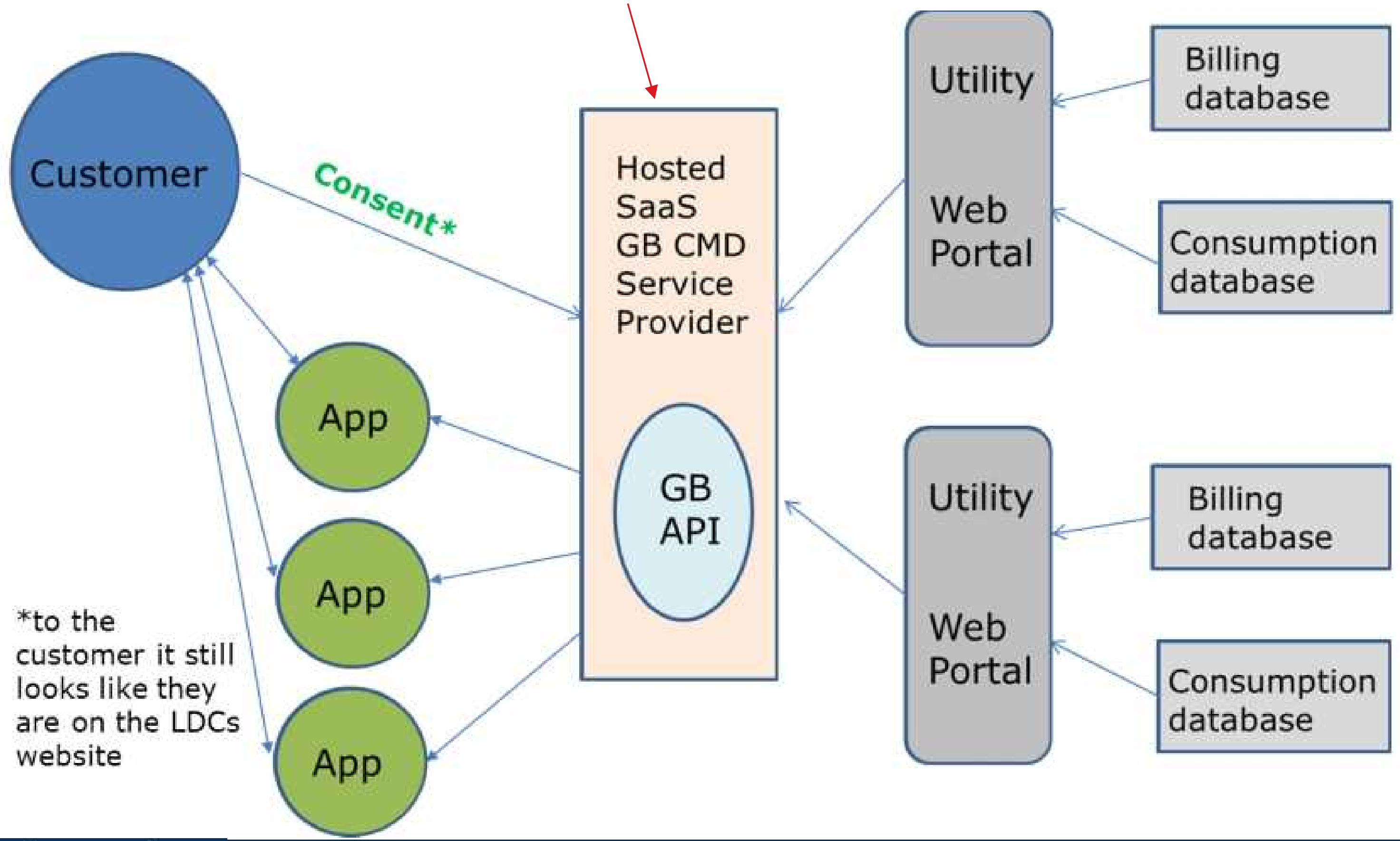
Option	Details
Green Button Download My Data (DMD)	• Provides customers with the ability to download their utility data directly, through their utilities' websites • Data is downloaded in XML and is provided in a consistent format
Green Button Connect My Data (CMD)	• Provides customers with the ability to share their data with solution providers and compatible databases in an automated way, based on consumer authorization • Process follows Privacy By Design principles

UTILITY TYPE

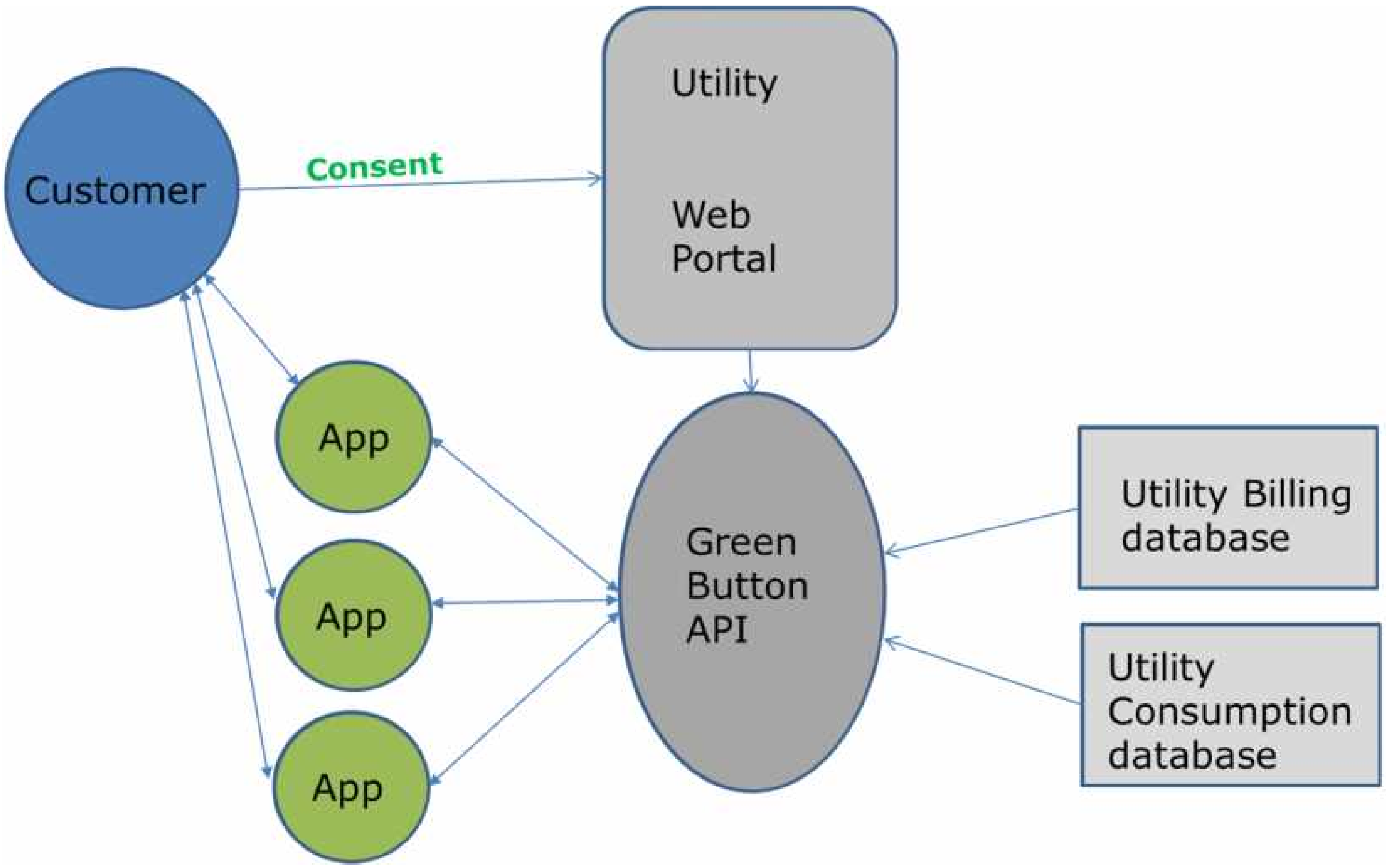
Utility Type	Key Factors in Analysis	Details
Electricity	Utility Population and Sizes	• 7 Large, 21 Medium, 44 Small
	Metering Infrastructure	• All are metered • Most have completed smart meter implementation for Residential and Small Commercial • Submeters exist for many buildings (but unknown to what extent by utilities)
	Total Number of Accounts	• 5,162,768 accounts
Natural Gas	Utility Population and Sizes	• 2 Large, 1 Small
	Metering Infrastructure	• All are metered • Combination of Automatic Meter Reading (AMR) and analog meters
	Total Number of Accounts	• 3,423,622 accounts
Water	Utility Population and Sizes	• 39 Large, 91 Medium, 550 Small
	70% of Small Water Utilities are Metered	• Only metered utilities included in analysis
	Of the Metered Utilities: Utility Population and Sizes	• 39 Large, 91 Medium, 385 Small
	Total Number of Accounts	• 4,955,366 accounts

IMPLEMENTATION TYPE: HOSTED

- Difference between hosted implementation types is in the number of providers (fewer providers creates efficiencies in cost and effort)



IMPLEMENTATION TYPE: IN-HOUSE



IMPLEMENTATION TYPE

Lower Cost → Higher Cost

Single Integrated Hosted	Multi-Integrated Hosted	Non-Integrated Hosted	In-House
Hosted SaaS provider implements Green Button for all utilities	Limited number of Green Button hosted SaaS platforms are used by all utilities*	Each utility has the option to develop/ procure its own GB SaaS hosted platform	Each utility develops its own platform on its own IT systems
3 implementation platforms (1 per utility type)	5 implementation platforms	591 implementation platforms	591 implementation platforms
Single platform development cost per utility type.	Platform development cost multiplied by 12	Multiple development costs	All utilities incur development costs

*Hypothetical scenario demonstrating potential synergies

RESULTS

CONTEXT AND CONSIDERATIONS

- Green Button is a relatively new standard, with little existing data on implementation.
  - Information gathered was largely new and primary-source based.
  - Data for some sectors and/or costs and benefits is more widely available than others.
  - Where detailed, granular data does not exist or the project scope did not allow for in-depth research, our team developed assumptions and proxies.
    - *The analysis shows scenarios that are cost-effective and ones that are not.*
    - *There is a margin of error associated with the results. Ratios should not be interpreted as exact; they should be interpreted as indicative.*
- Results are presented at the societal level, not for individual sectors or customer groups.
  - However, the results have been built up from inputs at the sector and customer-group level rather than developed from a top-down approach.
- Results include both direct and indirect benefits.

SUMMARY OF SCENARIO RESULTS

- Benefit/Cost Ratios of Green Button **DMD only**

Utility Type	Single Integrated Hosted		Multi-Integrated Hosted		Non-Integrated Hosted		In-House	
	5-year	10-year	5-year	10-year	5-year	10-year	5-year	10-year
Electricity	2.2	3.5	2.1	3.4	1.8	3.03	1.4	2.5
Electricity and Natural Gas	2.3	2.9	2.1	2.8	1.7	2.5	1.3	2.1
Electricity, Natural Gas, and Water	0.3	0.8	0.6	1.4	0.2	0.5	0.2	0.6
Natural Gas Component**	2.4	1.8	2.1	1.7	1.9	1.4	0.5	0.8
Water Component**	0.04	0.1	0.1	0.3	0.02	0.1	0.03	0.1

*Utility-hosted
**Incremental results

SUMMARY OF SCENARIO RESULTS

- Benefit/Cost Ratios of Green Button **DMD/CMD**

Utility Type	Single Integrated Hosted		Multi-Integrated Hosted		Non-Integrated Hosted		In-House*	
	5-year	10-year	5-year	10-year	5-year	10-year	5-year	10-year
Electricity	4.1	3.6	4.04	3.6	3.5	3.5	3.2	3.4
Electricity and Natural Gas	4.4	3.8	4.4	3.8	3.9	3.7	3.5	3.6
Electricity, Natural Gas, and Water	1.9	2.8	1.8	2.8	1.4	2.5	1.1	2.3
Natural Gas Component**	6.2	4.9	6.0	5.0	5.6	4.8	5.4	4.7
Water Component**	0.5	1.1	0.5	1.04	0.3	0.8	0.3	0.7

*Utility-hosted
**Incremental results

RESULTS: GREEN BUTTON OPTION

- Deploying Green Button Connect My Data (CMD) in conjunction with Download My Data (DMD) provides greater benefits than DMD alone.
  - While consistently formatted electronic data downloads (DMD-only) are beneficial for sophisticated customers, the ability to develop tailor-made solutions and applications and create efficiencies with data transfer and authorization multiply the benefits when CMD is added.

RESULTS: UTILITY TYPES

- Deploying Green Button for electricity and natural gas only is the most cost-effective option.
  - The benefits are highest for electricity, and the costs are lower for natural gas because there are so few utilities.
- Including water is cost-effective from a societal level when combined with electricity and natural gas.
- However, this is primarily based on the benefits from electricity and natural gas outweighing the costs of implementing Green Button for water.
  - The majority of water utilities are small, with limited resources and minimal IT and metering infrastructure.
  - The costs to become "Green Button ready" would be significant for them, and the benefits are limited.
  - Only water utilities with metering infrastructure were included in the analysis. Water utilities not included in the analysis are not generally planning to upgrade their infrastructure in the next five years.

WATER UTILITIES

- Implementing Green Button for all water utilities on their own (i.e. not combined with electricity and natural gas) is not cost-effective under most options due to:
  - Higher integration costs:
    - *Large number of metered water utilities*
    - *Each one results in multiplied integration and platform costs*
  - Lower unit benefits per customer. For example:
    - *Lack of engagement in water conservation (not including large customers)*
    - *Lower bill frequency (so less chance to use data/receive benefits)*
- Water **may** be cost-effective on its own with Single Integrated Hosted and Multi-Integrated Hosted implementations over a 10-year horizon.
  - The result is well within the margin of error.
  - However, in developing our analysis, we have erred on the side of being conservative rather than permissive in terms of benefits.

Option	Single Integrated Hosted		Multi-Integrated Hosted		Non-Integrated Hosted		In-House*	
	5-year	10-year	5-year	10-year	5-year	10-year	5-year	10-year
DMD	0.04	0.1	0.1	0.3	0.02	0.1	0.03	0.1
DMD/CMD	0.5	1.1	0.5	1.04	0.3	0.8	0.3	0.7

WATER UTILITIES

- There are some options that increase the cost-effectiveness of implementing Green Button for water utilities on their own, including implementing it only for the largest utilities:
  - 37 utilities, representing ~78% of the population
  - Lower integration costs:
    - *Fewer number of utilities, reducing integration and platform costs*
  - Larger number of customers per utility, reducing the per-customer cost

Deployment	Non-Integrated Hosted		Single Integrated Hosted		In-House*	
	5-year	10-year	5-year	10-year	5-year	10-year
DMD/CMD	1.7	1.7	1.2	1.8	0.8	1.4

RESULTS: IMPLEMENTATION TYPE

- The Single Integrated Hosted implementation is the most cost-effective option when implementing for all utility types.*
- Single Integrated and Multi-Integrated Hosted are equally cost-effective when implementing only for electricity and natural gas.
- A Non-Integrated Hosted option is assumed to increase costs because of the need to develop a greater number of platforms.
- In-House Hosting is the least efficient because it is not part of utilities' core business.

*For Green Button DMD+CMD over 10 years, a Multi-Integrated implementation has the same cost-benefit ratio as the Single Integrated option.

Key Scenario 1: Single Integrated/Multi-Integrated Hosted Electricity & Natural Gas

Dimension	Results	
Cost-Benefit Ratio	**5-Year Horizon**	4.4
	10-Year Horizon	3.8
Utility Type		Electricity and Natural Gas
Implementation		Single Integrated Hosted; Multi-Integrated Hosted
Green Button Option		Download My Data and Connect My Data

KEY SCENARIO 2: SINGLE INTEGRATED HOSTED ELECTRICITY, NATURAL GAS & WATER

Dimension	Results	
Cost-Benefit Ratio	**5-Year Horizon**	1.9
	10-Year Horizon	2.8
Utility Type		Electricity, Natural Gas and Water
Implementation		Single Integrated Hosted
Green Button Option		Download My Data and Connect My Data

KEY SCENARIO 3: MULTI-INTEGRATED HOSTED
ELECTRICITY, NATURAL GAS & WATER

Dimension	Results	
Cost-Benefit Ratio	5-Year Horizon	1.8
	10-Year Horizon	2.8
Utility Type		Electricity, Natural Gas and Water
Implementation		Multi-Integrated Hosted
Green Button Option		Download My Data and Connect My Data

APPENDIX B: COST-BENEFIT ANALYSIS INPUT ASSUMPTIONS

Green Button Cost-Benefit Analysis Input Assumptions

Appendix B

General Inputs:

General Input	Source	Notes
Discount Rate (Societal): 2%	IESO real discount rate (CDM EE Cost-Effectiveness Test Guide): http://www.ieso.ca/-/media/files/ieso/document-library/conservation/ldc-toolkit/cdm-ee-cost-effectiveness-test-guide-v2-20150326.pdf?la=en Ontario long-term bond rates: http://www.ofina.on.ca/pdf/bond_issue_details_DMTN228_to_R19.pdf	Adjustment to IESO real discount rate of 4% (CDM EE Cost-Effectiveness Test Guide) to reflect conservative view of 30-year Ontario real bond rates of 1.2%). The social discount rate represents the public benefit perspective of the Green Button framework, and based on industry practices, normally reflects the long-term treasury bonds borrowing rates. For the Green Button Framework analysis, considering the IESO social discount rate, a 2% social discount rate was selected.
Inflation Rate: 1.7%	Ontario's annual inflation rate in June 2016: http://inflationcalculator.ca/2016-cpi-and-inflation-rates-for-ontario/	As per leading industry practices, the cost-effectiveness analysis uses real values, and do not require adjustments for inflation.
Monetary values base year: 2016	Costs and benefits are expressed in 2016 values.	
Participation in Green Button	Rogers' Diffusion of Innovation	Varies by cost/benefit category

Population Inputs:

Group to which Costs/Benefits are Assigned	Sub Group	Population	Source	Submeter penetration	Source
Buildings/ Facilities	Large Commercial	32,011	Statistics Canada, Survey of Commercial and Institutional Energy use - Buildings 2009	0.03%	Estimates developed from IT Survey
	Small Commercial	112,672	Statistics Canada	0.40%	
	Large Industrial	120	Statistics Canada	0	
	Institutional	19,630	Statistics Canada	0.03%	
	Residential	3,342,822	Statistics Canada, Private Households, by structural type of dwellings	3.40%	
Total Utility Accounts per customer type	Large Commercial	54,706	OEB 2014 Yearbook of Electricity Distributors; Utility IT Survey; For water utilities: based on proportion of electric to water accounts	0.03%	Estimates for percentage of accounts by customer type developed from IT Survey
	Small Commercial	432,565		0.40%	
	Large Industrial	120		0.00%	
	Institutional	19,637		0.03%	
	Residential	4,655,740	OEB 2014 Yearbook of Electricity Distributors; Utility IT Survey; For water utilities: based on population in each municipality, average numer of individuals per household in Ontario	3.40%	
Electricity Utility	Large	7	OEB 2014 Yearbook of Electricity Distributors		
Electricity Utility	Medium	21	OEB 2014 Yearbook of Electricity Distributors		
Electricity Utility	Small	44	OEB 2014 Yearbook of Electricity Distributors		
Natural Gas Utility	Large	2	OEB 2014 Yearbook of Natural Gas Distributors		
Natural Gas Utility	Small	1	OEB 2014 Yearbook of Natural Gas Distributors		
Water Utility	Large	39	http://www.watertapontario.com/asset-map/utilities/water-and-wastewater-utilities		
Water Utility	Medium	91	http://www.watertapontario.com/asset-map/utilities/water-and-wastewater-utilities		
Water Utility	Small	385	Assumes 70% are metered (IT Survey); http://www.watertapontario.com/asset-map/utilities/water-and-wastewater-utilities		

Green Button Cost-Benefit Analysis Input Assumptions

Appendix B

Costs:

Category and Input	Source	Notes
One-Time Green Button Implementation Costs		
Use Case: Set-Up and Integration Costs - One Time - DMD/CMD		
Key Inputs:		
Platform Setup Costs	Stakeholder Interviews, Solution Providers survey	Includes front-end solutions, cloud services, Green Button platform, development and testing, and registration costs
Utility Integration Costs, variable by utility size	Stakeholder interviews with Ontario GB Pilot utilities	Includes ETL protocols and other integration costs such as integration with customer portals, meter data, external testing and validation, etc.
Variability by implementation scenario	Professional judgement and stakeholder interviews	Setup Costs account for the number of platforms in each implementation scenario (single integrated = 3 (1 per utility type), in-house/non-integrated = 591 (1 per utility), multi-integrated = 12 (5 per utility type except 2 for natural gas)
		Efficiencies increase from in-house, to non-integrated, to single-integrated. Separate assumptions were not developed for multi-integrated hosted (centralized assumptions were used with a simple multiplication of development costs)
Forecasted Participation	Professional judgement	100% implementation within 4 years: 35%, 70%, 92%, 100%
		Accounts for current implementation of DMD and CMD in electricity utilities
Use Case: Set-Up and Integration Costs - One Time - DMD		
Key Inputs:		
Platform Setup Costs	Stakeholder Interviews, Solution Providers survey	Includes front-end solutions, cloud services, Green Button platform, development and testing (including of required security and privacy mechanisms and protocols), and registration costs
Utility Integration Costs, variable by utility size	Stakeholder interviews	Subset of DMD/CMD costs, based on cost breakdown and professional judgment. Includes ETL protocols and other integration costs such as integration with customer portals, meter data, external testing and validation, etc.
Variability by implementation scenario	Professional judgement and stakeholder interviews	Setup Costs account for the number of platforms in each implementation scenario (single integrated = 3 (1 per utility type), in-house/non-integrated = 591 (1 per utility), multi-integrated = 12 (5 per utility type except 2 for natural gas)
		Efficiencies increase from in-house, to non-integrated, to single-integrated. Separate assumptions were not developed for multi-integrated hosted (centralized assumptions were used with a simple multiplication of development costs)
Forecasted Participation	Professional judgement	100% implementation within 4 years: 35%, 70%, 92%, 100%
		Accounts for current implementation of DMD in electricity utilities

Annual Green Button Implementation Costs		
Key Inputs:		
Annual Variable cost by participating customer	Stakeholder Interviews	Costs are for maintenance and ongoing operations
Impact of Implementation Scenarios	Professional judgement and stakeholder interviews	Efficiencies increase from utility-hosted, to non-integrated hosted, to single-integrated.
Forecasted Participation	Modeled through the Adoption/Penetration Rate analysis	

Retrofit Costs		
General Notes:	Costs are total measure costs.	
	They do not include potential costs from new programs developed as a result of Green Button or additional program administrator costs that could be incurred due to higher participation in CDM/DSM programs (which are not a one-to-one relationship).	
Key Inputs:		
Unit Costs of Retrofit Activity ($/conservation benefit)	Ontario utility and other Canadian CDM/DSM Plans	Water: assumes similar cost per benefit value as electricity
Forecasted Participation	Rogers' Diffusion of Innovation	Uses the same adoption rate as retrofit activity (see benefits).

Green Button Cost-Benefit Analysis Input Assumptions

Appendix B

Benefits:

Category and Input	Source	Notes
Utility Consumption, Billing and Generation Data Process Efficiencies		
Customers		
General Notes:	**GB Phase:** DMD and CMD do not bring the same value to participants	
	Customer Type: Residential and Small Commercial customers have less sophisticated processes to collect and analyze consumption data - GB translates into higher unit benefits	
	Current Practices: Customers already accessing consumption data in e-format will have lower benefits than new participants	
	Utility Type: The benefits are higher when more utility types are involved. Customers need to access or request data to each utility type individually.	
	Ownership Status: C&I Building Owners and Property Managers are experiencing higher benefits: benchmarking efficiencies, more use cases for energy tracking.	
Key Inputs:		
Value by customer participating through a CMD solution (quantified through avoided costs)	Stakeholder consultations and interviews	
Assigning benefit unit value	Source Data: interviews with stakeholders	Stakeholders clearly identified electricity as the key utility consumption data that would provide the majority of benefits for a GB implementation. The distribution reflects the feedback provided by stakeholders.
Benefits for a new user of utility data through CMD, for electricity	Stakeholder consultations and interviews	Distribution by utility type based on the value of each utility type's data to customers (+/-64% of total benefits attributed to electricity)
Benefits for a new user of utility data through CMD, for natural gas	Stakeholder consultations and interviews	Distribution by utility type based on value of each utility type's data to customers (+/-22% of total benefits attributed to natural gas
Benefits for a new user of utility data, through CMD, for water	Stakeholder consultations and interviews	Distribution by utility type based on value of each utility type's data to customers (+/-14% of total benefits attributed to water)
Benefits for existing users of utility data in e-format	Interviews with Stakeholders & Professional Judgement	Incremental benefits to current process. Benefits stem from simplified process and standardized format. A minimal dollar value was assigned because several of the key benefits were already being experienced by those customers.
Benefits for tenants	Professional judgement used to link to study addressing behavioural spillover effects	
Assigning customers to appropriate category		
Existing users of utility data in e-format	Utility IT surveys	
O.Reg. 20/17	Communication with the Ministry of Energy; Ministry of Energy "Energy use and greenhouse gas emissions from the Broader Public Sector: 2014" (reporting and non-reporting organizations).	Institutional buildings accessing data through the EBT Hub are excluded from this class. Includes the 10% of federal and provincial institutional buildings not included in O.Reg. 397/11
New C&I users of utility data	Communication with the Ministry of Energy; Ministry of Energy "Energy use and greenhouse gas emissions from the Broader Public Sector: 2014" (reporting and non-reporting organizations).	Remaining proportion of population of C&I buildings not currently accessing consumption data or subject to O.Reg. 20/17
New residential users of utility data	See number of customer accounts and number of buildings in General Inputs	
Forecasting Penetration		
Based on diffusion of innovation algorithm	Rogers' Diffusion of Innovation	This theory has been applied successfully to DSM/CDM programs to forecast participation.
Parameters of Algorithm	Professional judgement based on barriers for each customer type, considering sophistication in consumption data management, resource availabilities (lower penetration for small commercial and residential)	
	Other requirements (compliance to O.Reg. 20/17)	

Green Button Cost-Benefit Analysis Input Assumptions

Appendix B

Benefits (continued):

Category and Input	Source	Notes
Utility Consumption, Billing and Generation Data Process Efficiencies		
Customers		
Use Case: Increased Conservation: Behavioural & Operational		
General Sources:	Literature review including: - Murray, M. and J. Hawley. 2016. Got Data? The Value of Energy Data Access to Consumers.Mission:Data. - Navigant Consulting Inc., 2016. Home Energy Report Opwer Program PY7 Evaluation Report: Commonwealth Edison. - Opinion Dynamics. 2013. Massachusetts Cross-Cutting Behavioral Program Evaluation Integrated Report: Massachusetts Energy Efficiency Advisory Council and Behavioral Research Team.	
General Notes:	Conservation savings achieved as a result of increased access to data.	
	Does not differentiate between savings within and outside of CDM/DSM programs.	
	Does not include potential savings resulting from new programs developed as a result of Green Button.	
	Behavioural savings from access to consumption data have been evaluated to vary between 4 and 12%, depending on the technology involved and engagement methodologies.	
	The model assumes a conservative 1% for behavioural savings to recognize that the utilities do not have control over the engagement.	
	The penetration curve selected were modest, and reflects early evidence of use of GB-enabled apps in other jurisdictions.	
	A DSM-driven GB-related program would elicit a much higher level of participation than what is included in the model. Current behavioural programs available (Home Energy Report) claim 1 to 2% savings across the entire population receiving the reports. Savings by individual customers attributable to reports can be much higher than this.	
Key Inputs:		
Average Building Electricity Consumption	Average Electricity Intensity in Ontario, based on NRCAN's Comprehensive Energy Use Database	Conservative estimates were used due to unknowns regarding actual impacts
Average Building Natural Gas Consumption	Average Electricity Intensity in Ontario, based on NRCAN's Comprehensive Energy Use Database	Conservative estimates were used due to unknowns regarding actual impacts
Average Building Water Consumption	Calculated from Total Water Consumption per Capita (Sustainable Water Management Division, Environment Canada. 2011 Municipal Water Use Report – Municipal Water Use 2009 Statistics), Residential Water Consumption per Capita, number of accounts.	Assuming water consumption across customer class is proportional to electricity consumption. Conservative estimates were used due to unknowns regarding actual impacts
Value of Conservation	Avoided Costs - based on Union Gas DSM Plan 2015-2018 , app. B (the Plan includes avoided costs for natural gas, electricity, and water	Conservative estimates were used due to unknowns regarding actual impacts
Conservation Level	Literature Review of conservation programs based on access to utility consumption data (Murray, M. and J. Hawley. 2016. Got Data? The Value of Energy Data Access to Consumers. Mission:Data)	Conservative estimates were used due to unknowns regarding actual impacts
Calculation:		
Behavioural & Operational Savings Unit Value per building type	Average Building Utility Consumption by building type * Avoided Costs * Conservation Level	
Electricity Retrofit Savings	Ontario utility and other Canadian CDM/DSM Plans and average energy rates	
Natural Gas Retrofit Savings	Ontario utility and other Canadian CDM/DSM Plans and average energy rates	
Water Retrofit Savings	Conservatively estimated based on electricity/natural gas potential savings (Ontario utility and other Canadian CDM/DSM Plans and average energy rates)	Conservatively estimated based on electricity/natural gas potential savings
Forecasting Penetration		
Based on diffusion of innovation algorithm	Rogers' Diffusion of Innovation	This theory has been applied successfully to DSM/CDM programs to forecast participation.
Parameters of Algorithm	Professional judgement based on barriers for each customer type, considering sophistication in consumption data management, resource availabilities (lower penetration for small commercial and residential)	
Results:		Residential: Participation after 5 yrs is 1% of total customers
		Commercial participation after 5 yrs: large: 6%, small: 2%, institutional: 6%

Green Button Cost-Benefit Analysis Input Assumptions

Appendix B

Benefits (continued):

Category and Input	Source	Notes
Utility Consumption, Billing and Generation Data Process Efficiencies		
Customers (continued)		
Use Case: Increased Conservation: Retrofit		
Key Inputs:		
Average Building Electricity Consumption	Average Electricity Intensity in Ontario, based on NRCAN's Comprehensive Energy Use Database	
Average Building Natural Gas Consumption	Average Electricity Intensity in Ontario, based on NRCAN's Comprehensive Energy Use Database	
Average Building Water Consumption	Calculated from Total Water Consumption per Capita, Residential Water Consumption per Capita, number of accounts per capita	Assuming water consumption across customer class is proportional to electricity consumption
Value of Conservation	Avoided Costs - based on Union Gas DSM Plan 2015-2018, app. B (the Plan includes avoided costs for natural gas, electricity, and water)	
Conservation Level	Savings estimation based on evaluation experience and Ontario utility and other Canadian CDM/DSM Plans.	Conservative Estimate - 10% savings - average of retrofit activities considering several achieve 20% more savings with utility conservation programs.
Calculation:		
Behavioural & Operational Savings Unit Value per building type	Average Building Utility Consumption by building type* Avoided Costs * Conservation Level	
Forecasting Penetration:		
Based on diffusion of innovation algorithm	Rogers' Diffusion of Innovation	This theory has been applied successfully to DSM/CDM programs to forecast participation.
Parameters of Algorithm	Professional judgement based on barriers for each customer type, considering sophistication in consumption data management, resource availabilities (lower penetration for small commercial and residential)	
Results:		Residential: Participation after 5 yrs is 0.4% of total customers - this captures conservation activities requiring expenditure
		Commercial participation after 5 yrs: large: 0.7%, small: 0.12%, institutional:0.7%

Category and Input	Source	Notes
Solution Providers		
Use Case: Ongoing Utility Consumption Monitoring and Benchmarking		
Key Inputs:		
Average benefit per building, per building type, utility type	Interviews with Stakeholders	This benefit is included as a dollar value reflecting reduced effort to access utility consumption data for monitoring and benchmarking activities
Forecasting Penetration		
Based on diffusion of innovation algorithm	Rogers' Diffusion of Innovation	This theory has been applied successfully to DSM/CDM programs to forecast participation
Parameters of Algorithm	Professional judgement based on barriers, interviews with stakeholders	
Use Case: Engineering Services - One-Time Services Requiring Utility Consumption Data		
Key Inputs:		
Average benefit per building, per building type, utility type	Interviews with Stakeholders	This benefit stems from reduced effort to access utility consumption data to conduct engineering analysis
Forecasting Penetration		
Based on diffusion of innovation algorithm	Rogers' Diffusion of Innovation	This theory has been applied successfully to DSM/CDM programs to forecast participation
Parameters of Algorithm	Professional judgement based on barriers, interviews with stakeholders	

Category and Input	Source	Notes
Utility Reduced Customer Care Effort		
Key Inputs:		
Annual Cost Reduction- reduced customer care efforts - by utility type and size	Stakeholder Interviews, Utility IT Surveys	
Forecasting Penetration	Professional Judgement	100% implementation within 4 years: 35%, 70%, 92%, 100%

Category and Input	Source	Notes
Utility CDM/DSM Program Efficiencies and Innovations		
Key Inputs:		
Annual Cost Reduction- CDM/DSM Program Efficiencies and Innovations - by utility type and size	Values estimated based on Stakeholder Interviews	This is a token benefit expressed in $ per utility

APPENDIX C: COSTS AND BENEFITS OVERVIEW TABLE

Proposed Use Cases: Costs and Benefits Overview Table

Appendix C

	Customer Groups																													
	Property Owners/Managers															Tenants/Residents														
	Large Commercial			Small Commercial			Large Industrial			Institutional			Residential			Large Commercial			Small Commercial			Large Industrial			Institutional			Residential		
Benefits	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual
Utility Consumption, Billing and Generation Data Process Efficiencies																														
Energy tracking (voluntary and internal) - customers who currently gather and track data	Y			Y			Y			Y			Y			Y			Y			Y			Y			Y		
Energy audit efficiencies																														
Energy tracking																														
Energy and water reporting and benchmarking																														
Consistent machine readable data among multiple utilities																														
Increased data (consumption, billing and generation) accuracy/ quality																														
Simplified data sharing authorization process																														
Increased frequency and granularity of utility data																														
Energy and water reporting and benchmarking - customers' future data collection related to Bill 135	Y			Y			Y			Y			Y			Y			Y			Y			Y			Y		
Energy audit efficiencies (new customer requirements)																														
Energy tracking (new customer requirements)																														
Energy and water reporting and benchmarking																														
Consistent machine readable data among multiple utilities																														
Increased data (consumption, billing and generation) accuracy/quality																														
Simplified data sharing authorization process																														
Increased frequency and granularity of utility data																														
Increased operational efficiencies within utilities from improvements to IT systems																														
Increased Conservation																														
Non-retrofit savings		Y			Y			Y			Y			Y			Y			Y			Y			Y			Y	
Greater behavioural-based conservation																														
Greater operational savings in buildings																														
Increased CDM/DSM program participation																														
Increased energy efficiency retrofit savings		Y			Y			Y			Y			Y																
Increased energy efficiency / conservation education																														
Increased CDM/DSM program participation																														
Other Conservation																														
CMD/DSM program efficiencies and innovations																														
New CDM/DSM program design based on Green Button																														
CDM/DSM program implementation efficiencies																														
CDM/DSM program evaluation efficiencies																														

Quantitative input into model	Benefit that is not broken out quantitatively in the model	Category Heading

Proposed Use Cases: Costs and Benefits Overview Table

Appendix C

	Customer Groups																													
	Property Owners/Managers															Tenants/Residents														
	Large Commercial			Small Commercial			Large Industrial			Institutional			Residential			Large Commercial			Small Commercial			Large Industrial			Institutional			Residential		
Benefits	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual
Increased Real Estate Value			Y			Y			Y			Y			Y															
Customer Service Benefits																														
Reduced customer care effort																														
Increased customer satisfaction / engagement																														
Improved customer access to data																														
Support government policy objectives																														
Reduce/remove barriers to reporting & benchmarking requirements																														
Support OEB's customer education/customer control goals																														
Support Ontario's Conservation objectives and Climate Change Action Plan																														
Economic Development and Innovation																														
Job Creation																														
Improved Access to North American Market																														
Support new use cases and development of innovative services																														
Costs																														
GB Implementation Costs																														
GB infrastructure - cloud services, platform																														
GB infrastructure - front end																														
Security and privacy																														
Third-party applications - registration and testing																														
GB Utility Integration																														
Integration with customer portal																														
Computer information systems Extract, Transform, and Load (ETL) protocols																														
Meter Data																														
Integration with third-party meter data management																														
Testing																														
Marketing																														
Security and privacy																														
Increased energy efficiency retrofit costs		Y			Y			Y			Y			Y																

Quantitative input into model	Benefit that is not broken out quantitatively in the model	Category Heading

Proposed Use Cases: Costs and Benefits Overview Table

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Benefits	Utilities																										
	Electric Utilities									Natural Gas Utilities						Water Utilities											
	Electricity (Large)			Electricity (Medium)			Electricty (Small)			Natural Gas Utilities (Large)			Natural Gas Utilities (Small)			Water Utilities (Large)			Water Utilities (Medium)			Water Utilities (Small)			Water Utilities (linked to LDC)		
	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual
Utility Consumption, Billing and Generation Data Process Efficiencies																											
Energy tracking (voluntary and internal) - customers who currently gather and track data	Y			Y			Y			Y			Y			Y			Y			Y			Y		
Energy audit efficiencies																											
Energy tracking																											
Energy and water reporting and benchmarking																											
Consistent machine readable data among multiple utilities																											
Increased data (consumption, billing and generation) accuracy/ quality																											
Simplified data sharing authorization process																											
Increased frequency and granularity of utility data																											
Energy and water reporting and benchmarking - customers' future data collection related to Bill 135	Y			Y			Y			Y			Y			Y			Y			Y			Y		
Energy audit efficiencies (new customer requirements)																											
Energy tracking (new customer requirements)																											
Energy and water reporting and benchmarking																											
Consistent machine readable data among multiple utilities																											
Increased data (consumption, billing and generation) accuracy/quality																											
Simplified data sharing authorization process																											
Increased frequency and granularity of utility data																											
Increased operational efficiencies within utilities from improvements to IT systems																											
Increased Conservation																											
Non-retrofit savings																											
Greater behavioural-based conservation*																											
Greater operational savings in buildings*																											
Increased CDM/DSM program participation*																											
Increased energy efficiency retrofit savings																											
Increased energy efficiency / conservation education			Y			Y			Y			Y			Y			Y			Y			Y			Y
Increased CDM/DSM program participation*																											
Other Conservation																											
CMD/DSM program efficiencies and innovations		Y	Y		Y	Y		Y	Y		Y	Y		Y	Y			Y			Y			Y			Y
New CDM/DSM program design based on Green Button			Y			Y			Y			Y			Y			Y			Y			Y			Y
CDM/DSM program implementation efficiencies			Y			Y			Y			Y			Y			Y			Y			Y			Y
CDM/DSM program evaluation efficiencies			Y			Y			Y			Y			Y			Y			Y			Y			Y

Quantitative input into model	Benefit that is not broken out quantitatively in the model	Category Heading

Proposed Use Cases: Costs and Benefits Overview Table **Appendix C**

	Utilities																										
	Electric Utilities									Natural Gas Utilities						Water Utilities											
	Electricity (Large)			Electricity (Medium)			Electricty (Small)			Natural Gas Utilities (Large)			Natural Gas Utilities (Small)			Water Utilities (Large)			Water Utilities (Medium)			Water Utilities (Small)			Water Utilities (linked to LDC)		
Benefits	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual
Increased Real Estate Value																											
Customer Service Benefits																											
Reduced customer care effort	Y			Y			Y			Y			Y			Y			Y			Y			Y		
Increased customer satisfaction / engagement			Y			Y			Y			Y			Y			Y			Y			Y			Y
Improved customer access to data			Y			Y			Y			Y			Y			Y			Y			Y			Y
Support government policy objectives																											
Reduce/remove barriers to reporting & benchmarking requirements																											
Support OEB's customer education/customer control goals																											
Support Ontario's Conservation objectives and Climate Change Action Plan																											
Economic Development and Innovation																											
Job Creation																											
Improved Access to North American Market																											
Support new use cases and development of innovative services			Y			Y			Y			Y			Y			Y			Y			Y			Y
Costs																											
GB Implementation Costs	Y			Y			Y			Y			Y			Y			Y			Y			Y		
GB infrastructure - cloud services, platform																											
GB infrastructure - front end																											
Security and privacy																											
Third-party applications - registration and testing																											
GB Utility Integration	Y			Y			Y			Y			Y			Y			Y			Y			Y		
Integration with customer portal																											
Computer information systems Extract, Transform, and Load (ETL) protocols																											
Meter Data																											
Integration with third-party meter data management																											
Testing																											
Marketing																											
Security and privacy																											
Increased energy efficiency retrofit costs*																											

*Included as a cost/benefit to end users (customers) rather than utilities

Proposed Use Cases: Costs and Benefits Overview Table

Appendix C

	Additional Stakeholders														
	Government									Third Parties					
	Gov Depts			IESO			OEB			SaaS GB Implementation Providers			EE/Technical Service Solution Providers		
	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual
Utility Consumption, Billing and Generation Data Process Efficiencies															
Energy tracking (voluntary and internal) - customers who currently gather and track data										Y			Y		
Energy audit efficiencies															
Energy tracking															
Energy and water reporting and benchmarking															
Consistent machine readable data among multiple utilities															
Increased data (consumption, billing and generation) accuracy/ quality															
Simplified data sharing authorization process															
Increased frequency and granularity of utility data															
Energy and water reporting and benchmarking - customers' future data collection related to Bill 135										Y			Y		
Energy audit efficiencies (new customer requirements)															
Energy tracking (new customer requirements)															
Energy and water reporting and benchmarking															
Consistent machine readable data among multiple utilities															
Increased data (consumption, billing and generation) accuracy/quality															
Simplified data sharing authorization process															
Increased frequency and granularity of utility data															
Increased operational efficiencies within utilities from improvements to IT systems															
Increased Conservation															
Non-retrofit savings															
Greater behavioural-based conservation															
Greater operational savings in buildings															
Increased CDM/DSM program participation															
Increased energy efficiency retrofit savings															
Increased energy efficiency / conservation education						Y									
Increased CDM/DSM program participation															
Other Conservation															
CMD/DSM program efficiencies and innovations												Y			
New CDM/DSM program design based on Green Button															Y
CDM/DSM program implementation efficiencies															Y
CDM/DSM program evaluation efficiencies						Y									

Quantitative input into model	Benefit that is not broken out quantitatively in the model	Category Heading

Proposed Use Cases: Costs and Benefits Overview Table **Appendix C**

	Additional Stakeholders														
	Government									Third Parties					
	Gov Depts			IESO			OEB			SaaS GB Implementation Providers			EE/Technical Service Solution Providers		
	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual	Direct Quant	Indir. Quant	Qual
Increased Real Estate Value															
Customer Service Benefits															
Reduced customer care effort															
Increased customer satisfaction / engagement															
Improved customer access to data															
Support government policy objectives															
Reduce/remove barriers to reporting & benchmarking requirements			Y												
Support OEB's customer education/customer control goals									Y						
Support Ontario's Conservation objectives and Climate Change Action Plan			Y			Y			Y						
Economic Development and Innovation															
Job Creation			Y							Y			Y		
Improved Access to North American Market			Y									Y			Y
Support new use cases and development of innovative services												Y			Y
Costs															
GB Implementation Costs															
GB infrastructure - cloud services, platform															
GB infrastructure - front end															
Security and privacy															
Third-party applications - registration and testing**															
GB Utility Integration															
Integration with customer portal															
Computer information systems Extract, Transform, and Load (ETL) protocols															
Meter Data															
Integration with third-party meter data management															
Testing															
Marketing															
Security and privacy															
Increased energy efficiency retrofit costs															

**Included within costs to utilities but not for SaaS implementation providers as it is a business-related cost built into existing costs

APPENDIX D: CONSERVATION METHODOLOGY

The following section walks through the methodology, assumptions and inputs used to estimate impacts from increased conservation activity resulting from improved access to utility consumption and billing data. We use building retrofits as the basis of the example, and **the same methodology is used for behaviour-based conservation**.

INCREASED CONSERVATION

ALGORITHM

Our general methodology links estimated energy and water savings to avoided costs to derive an annualized benefit from energy conservation. The general algorithm used is:

Conservation Benefit = Unitary Benefit * Participation

Unitary Benefit = % Savings * Annual Consumption * AC

Where:

- **Conservation Benefit:** Total annual conservation benefits from increased retrofit activity
- **Unitary Benefit:** Average annual benefit value per participant
- **% Savings:** Percentage of total building or house consumption saved through retrofit
- **Annual Consumption:** Total yearly building or house consumption (electricity, natural gas or water)
- **AC:** Utility avoided costs
- **Participation:** Annual number of participants

Where additional information was available to assess the unitary benefit value, an alternative approach based on the available information was used. This is notably the case for natural gas benefits in the residential sector. For natural gas savings, Union Gas presents unitary savings for its Home Renovation program. Considering that in the residential sector, the vast majority of benefits would be derived from measures and technologies covered under the Union Gas program, it was deemed a good representation of energy efficiency improvements.

The annual benefit value per participant is a model input, and the participation level is calculated through application of penetration curves. Inputs and assumptions used for each of these variables are presented below.

UTILITY SAVINGS

The impacts of increasing access to utility consumption and billing data has the potential to induce increased conservation activities, both through increased home and building retrofit activities (envelope improvements, high-efficiency HVAC equipment, etc.) and other actions requiring investments from the participants.

Residential Sector

For the residential sector, annual incremental savings are presented in the following table:

Utility Type	Annual Savings: Retrofit-Based Efficiency and Conservation	Annual Savings: Behaviour-Based Efficiency and Conservation
Electricity	10%	1%
Natural Gas	12%	1%
Water	3%	1%

Electricity Savings: Participants in Ontario's ecoENERGY retrofit program have realised a 20% reduction in their annual energy consumption.[1] More specifically for electricity, a Canmet Energy Study[2] has identified average potential savings representing 11% of individual home baseload electricity consumption (defined as lighting, major appliances, common plug-load and other atypical loads). We used 10%, which is lower than both these values, to ensure our analysis was conservative.

Natural Gas Savings: The potential measures to reduce consumption are essentially covered by Union Gas Home Renovation programs. Union Gas 2015-2020 DSM Plan provides information that allows us to calculate the average natural gas savings of 1,039 m^3/year for participants in the program. Considering that those natural gas savings were derived from utility programs, and that envelope improvements have higher barriers to participation (access to capital, discretionary measures, etc.) only 30% of those savings have been retained for the cost-benefit analysis.

Water Savings: In the absence of robust data on potential water savings improvements, a conservative 3% of annual load savings was used to estimate impacts.

[1] Natural Resources Canada, ecoENERGY Retrofit Statistics, August 1st, 2012.
[2] Canmet ENERGY: Base-Load Electricity Usage – Results from In-home Evaluations, 2012.

Commercial Sector

For the commercial sector, annual incremental savings are presented in the following table:

Utility Type	Annual Savings: Retrofit-Based Efficiency and Conservation	Annual Savings: Behaviour-Based Efficiency and Conservation
Electricity	10%	2%
Natural Gas	4%	2%
Water	3%	1%

Electricity and Natural Gas Savings: Annual savings factors were derived from Ontario's potential studies[3]. The economic potential was used as a representation of potential energy savings for the average C&I building in Ontario. Recognising that the economic potential (24% of commercial sector consumption for electricity and 23% for natural gas) represents all the savings economically feasible in buildings, the results from the potential studies were reduced to account for several barriers not addressed by increased access to energy consumption and billing information. The conservative estimates used for the analysis are also meant to reflect *incremental* savings specifically due to increased access to information. Specifically, for natural gas savings, we took into consideration the magnitude of required investments to achieve savings (i.e., most measures will require significant upfront capital investments to be realized). This is less of an issue for electricity measures, since lighting and plug load improvements can be individually procured for a reasonable cost.

For water savings, in the absence of robust information assessing the economic potential, we have used a conservative estimate of 3% annual savings.

[3] (ICF International, Natural Gas Potential Study, June 2016. http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2015-0117/ICF_Report_Gas_Conservation_Potential_Study.pdf;
Nexant Achievable Potential Study: Short Term Analysis, June 2016. http://www.ieso.ca/-/media/files/ieso/document-library/working-group/aps/aps-short-term-analysis-2016.pdf

BASELINE ANNUAL CONSUMPTION

Baseline average consumption was used to calculate unit annual savings per home or per building.

Residential Sector

Annual Utility Consumption – Residential Sector		
Utility Type	Annual Consumption	Source
Electricity	5,454 kWh	• Natural Resources Canada *Comprehensive Energy Use Database*, Residential Sector, Ontario, table 1 for 2014. o Total residential electricity consumption is reported as 118.7 PJ for 5,196,000 households. o For the purpose of the analysis, we used 85% of the calculated average consumption, considering notably the evolution of codes and standards and their potential impacts on electrical savings.
Natural Gas	2,600 m^3	• Navigant. *Analysis Investigating Revenue Decoupling for Electricity and Natural Gas Distributors in Ontario*, March 2014.
Water	213.5 m^3	• Environment Canada, *2011 Municipal Water Use Report:* o Assumes 225 liters per capita per day • Statistics Canada, *2011 Census*: o 2.6 persons per household

C&I Sector

The following values were used for the annual utility consumption for non-residential buildings in Ontario.

Annual Utility Consumption – Commercial and Institutional Sector				
Utility Type	Small Buildings (less than 10,000 ft^2)	Large Buildings (more than 10,000 ft^2)	Institutional	Source
Electricity (kWh)	42,464	508,905	344,105	Natural Resources Canada's Comprehensive Energy Use Database for the Commercial and Institutional Sector
Natural Gas (m^3)	7,442	89,912	60,309	
Water (m^3)	3,441	41,240	27,885	

The energy consumption values for non-residential buildings were derived from Natural Resources Canada's Comprehensive Energy Use Database for the Commercial and Institutional Sector. The total energy consumption by energy source for and total Floor Space was used to estimate an average energy intensity (GJ/m^2) for the C&I sector. This resulted in an average energy intensity of 116,25 kWh/m^2 for electricity and 20.374 m^3/m^2 for natural gas. The energy intensity factor was then applied to average building size for small, large and institutional buildings based on information from the Survey of Commercial and Institutional Energy use – Buildings 2009 (Detailed Statistical Report December 2012).

Building Size (ft^2)	Average Size	Count	Distribution	Estimated Electricity Consumption (kWh/yr)	Natural Gas Consumption (m^3/yr)
Less than 5,000	2,500	80082	49%	26,999	4,732
5,000-10,000	7,500	32141	20%	80,997	14,196
10,000 to 50,000	30,000	39054	24%	323,988	47,319
50,000 to 200,000	125,000	10103	6%	1,349,950	189,277
Greater than 200,000	200,000	2157	1%	2,159,920	378,554

The average energy consumption for small, large and institutional buildings were estimated through a weighted average of buildings for small (less than 10,000 ft^2), large (more than 10,000 ft^2) and institutional (more than 5,000 ft^2).

Information for water consumption for non-residential accounts is not readily available. Our analysis used a water use intensity of 380 L/ft^2[4] applied to the average size to estimate annual water consumption per building size.

AVOIDED COSTS

Annual resource benefits for all utility types were calculated using a fixed discount rate based on information provided in the Union Gas 2015-2020 DSM Plan, Appendix B. Electricity and water avoided costs remain constant in real value, whereas natural gas avoided costs vary annually. To simplify analysis, the cost-benefit models has assumed constant real avoided costs for each utility

[4] This water use intensity was derived from the City of Orillia Water Conservation and Efficiency Plan – 2014. The Plan indicates a 1,476 m^3 per non-residential connection. Considering Orillia is a small city, we have assumed that most of those connections would be in the small building category.

type. For natural gas, baseload avoided costs have been selected to remain conservative. The following table presents the avoided costs used in the analysis.

Utility Type	Avoided Costs
Electricity	0.1128 $/kWh
Natural Gas	0.21378 $/m^3
Water	2.2729 $/m^3

PARTICIPATION RATE

Participation rates for increased retrofit activities were based on the adoption curves developed for the cost-benefit model (see Penetration Level on page 26 of the report).

The table below presents the annual participation as a % of eligible population.

	Year									
	1	2	3	4	5	6	7	8	9	10
Small Commercial & Residential	0.66%	0.87%	1.13%	1.48%	1.93%	2.50%	3.24%	4.20%	5.41%	6.96%
Large Commercial, Industrial & Institutional	1.66%	3.20%	5.23%	7.86%	11.24%	15.52%	20.82%	27.22%	34.69%	43.04%

Eligible Population

The following table presents the eligible population for each customer class included in the analysis. We further include an applicability factor to further reduce the proportion of GB participants estimated to conduct retrofit activity due to increased accessibility to consumption and billing data. This was done to ensure our analysis was conservative and is highlighted as the Eligible Population in the table below.

SubGroup	Population (Number of Buildings)	Applicability Factor	Eligible Population	Source
Large Commercial	32,011	25%	8,003	Calculated from Survey of Commercial and Institutional Energy use – Buildings 2009 and Submeter Penetration Estimates developed from IT survey
Small Commercial	112,672	25%	28,168	
Large Industrial	120	25%	30	
Institutional	19,630	25%	4,908	
Residential	3,342,822	25%	835,706	

CALCULATION EXAMPLE

Below, we present the calculations conducted to evaluate the benefits for the DMD/CMD Electric Utility Only Scenario.

Unitary Benefit = % Savings * Annual Consumption * AC

Unit Benefit

Customer Class	% Savings (1)	Annual Consumption (kWh) (2)	Avoided Costs ($/kWh) (3)	Unit Benefits ($) (1)*(2)*(3)
Residential	10%	5454	0.11	60
Small Commercial	10%	42,464	0.11	467
Large Commercial	10%	508,906	0.11	5,598
Institutional	10%	344,105	0.11	3,785
Large Industrial	10%	763,359	0.11	8,397

Eligible Population

Customer Class	Population (1)	Applicability (2)	Eligible Population (1) * (2)
Residential	3,342,822	25%	835705
Small Commercial	112,672	25%	28168
Large Commercial	32,011	25%	8003
Institutional	19,630	25%	4908
Large Industrial	120	25%	30

ESTIMATION OF COSTS

The calculation of costs was conducted at a high level, as the cost-benefit analysis was focused on the overall impacts of a Green Button implementation rather than a measure-level analysis.

CALCULATION OF COST ESTIMATES

Because the benefits of increased conservation (energy savings) are calculated on an annualized basis, the costs are as well in order to ensure alignment. Our methodology for estimating costs is as follows:

- The energy savings as calculated in earlier sections of this appendix were used as a starting point.
- As a starting point, we used cost-benefit results from the Union Gas 2015-2020 DSM Plan to estimate the costs of the energy savings that were calculated. The Union Gas Plan was used as it provided the most detail for an entire portfolio.
- We made adjustments for applicable factors:
  - For the Residential Sector, because Total Resource Cost (TRC)-Plus values are available for the home renovation rebate, we incorporated those values and removed the generic 15% non-energy benefits adder from the DSM Plan.
    - We removed costs unrelated to energy retrofits (for example, audit costs), which resulted in costs being calculated as 89 percent of the TRC-plus costs.
    - This provided a cost-to-benefit ratio of 0.69 for natural gas.
    - For electricity and water, we applied a slightly lower ratio of 0.65. This decision was based on professional experience and a comparison of the results with measure-level annualized cost-to-benefit values from the IESO's Technical Reference Manual as well as internal sources from prior work.
  - For the Commercial, Industrial and Institutional Sector we followed the same methodology without the home renovation input adjustment. This resulted in 0.494 for natural gas and a 0.5 ratio for electricity and water.
- We applied these cost ratios to the annual benefit value to estimate the annualized costs.

Annual Benefits

Conservation Benefit = Unitary Benefit * Participation

Customer Class	Unit Ben ($) (1)	Eligible Pop. (2)	Annual Benefits ($) (1) * (2) * Adoption Curve for each year; Net Present Values use a 2% discount rate										
			Yr1	Yr2	Yr3	Yr4	Yr5	Yr6	Yr7	Yr8	Yr9	YR10	NPV (10yr)
Adoption Curve Res & Small Commercial			0.66%	0.87%	1.13%	1.48%	1.93%	2.50%	3.24%	4.20%	5.41%	6.96%	
Adoption Curve Large Commercial, Institutional, Large Industrial			1.66%	3.20%	5.23%	7.86%	11.24%	15.52%	20.82%	27.22%	34.69%	43.04%	
Residential	60	835,705	330,505	433,984	568,022	741,455	965,542	1,254,543	1,626,377	2,103,314	2,712,641	3,487,147	12,291,436
Small Commercial	467	28,168	86,733	113,889	149,064	194,578	253,384	329,226	426,805	551,967	711,870	915,122	3,225,605
Large Commercial	5,598	8,003	743,665	1,433,572	2,342,994	3,521,211	5,035,421	6,952,824	9,327,177	12,194,321	15,540,816	19,281,542	65,651,588
Institutional	3,785	4,908	308,356	594,421	971,506	1,460,046	2,087,903	2,882,941	3,867,450	5,056,291	6,443,892	7,994,959	27,221,980
Large Industrial	8,397	30	4,182	8,061	13,175	19,800	28,315	39,096	52,447	68,569	87,387	108,421	369,163

CALCULATION OF GREENHOUSE GAS REDUCTIONS

Greenhouse gas (GHG) reductions are calculated by multiplying the energy impacts as described above by the emissions factors provided by the Ministry of Energy:

GHG Reduction = Energy Savings * Emission Factor

As with other inputs, GHG emissions factors may not be up to date with current Ontario government GHG calculation assumptions because of the timeframe in which the analysis was conducted.

APPENDIX E: ADDITIONAL SCENARIO ANALYSIS

This appendix, developed in 2017 after the initial cost-benefit analysis was completed, provides additional results for Scenarios 1B (Multi-Integrated Hosted DMD/CMD for Electricity and Natural Gas utilities) and 2B (Multi-Integrated Hosted for All Utility Types), using a real discount rate of 3.5%, which has been used by the Ministry of Energy in other recent analyses.

SCENARIO 1B: MULTI-INTEGRATED HOSTED DMD/CMD (ELECTRICITY AND NATURAL GAS UTILITIES ONLY)

Table 1. Scenario 1B Cost Details

Cost Category	Cost Type	5-Year Analysis ($)	10-Year Analysis ($)	Scenario-Specific Assumptions
Implementation (One-time setup and integration costs)	Direct	3,982,723	3,986,847[1]	The setup cost for the Multi-Integrated scenario assumes: • 5 independent platforms for the electricity sector • 1 platform for the natural gas sector (because there are so few utilities) • 5 platforms for the water utilities
Operational Costs[2]	Direct	735,433	2,182,967	
Retrofit Costs	Indirect	10,573,953	60,072,210	
Total		**15,292,109**	**66,242,024**	

[1] Differences between the 5-year and 10-year Implementation Costs are an artefact of the mathematical function used to forecast implementation costs. The mathematical function forecasts the following rollout of Green Button through the first 5 years following enactment of the policy: 35%, 70%, 92%, 99%, 99.9%.
[2] Sum of net-present value of annual costs over the timeframe.

Table 2. Scenario 1B Benefits Details[3]

Benefit Category	Benefit Component	Benefit Type	5-Year Analysis ($)	10-Year Analysis ($)
Operational Efficiencies	Customers' Utility Consumption, Billing and Generation Data Process Efficiencies	Direct	17,221,476	54,410,886
	Process Efficiencies (Large Building Energy and Water Reporting and Benchmarking)	Direct	12,143,948	23,695,626
	Reduced Customer Care Efforts	Indirect	1,029,360	2,252,663
	CDM/DSM Program Efficiencies and Innovation	Indirect	849,831	1,859,779
Energy Efficiency and Conservation	Increased Conservation - Behavioural & Operational	Indirect	10,821,748	51,787,669
	Increased Conservation - Retrofits	Indirect	24,721,779	120,255,887
	Total		**66,788,142**	**254,262,509**

RESULTS

DETAILED RESULTS FOR THE MULTI-INTEGRATED VERSION OF THIS SCENARIO (SCENARIO 1B) ARE PRESENTED IN THE FOLLOWING TABLES.

BENEFIT-COST RATIOS:

Table 3. Scenario 1B Benefit-Cost Ratios

Ratio Type	5-Year Analysis	10-Year Analysis
Direct and Indirect Costs and Benefits	4.4	3.8
Direct Benefits and Costs only[4]	6.5	13.0

To illustrate how the costs and benefits are distributed across stakeholder groups, we present the following tables.

Table 4. Scenario 1B Costs by Stakeholder Group (5-year horizon)

Cost Category		Stakeholder Group	

[3] No scenario-specific assumptions required

[4] Direct benefits and costs are a subset of total benefits and costs. However, the direct benefits and costs *ratios* are higher than the total ratios because the magnitude of benefits to costs is different for direct results than for total results.

	Cost Type	Electricity Utility ($)	Natural Gas Utility ($)	Customers[5] ($)	Total ($)
Implementation (One-time setup and integration costs)	Direct	3,458,565	524,157	-	**3,982,723**
Operational Costs[6]	Direct	435,205	300,228	-	**735,433**
Retrofit Costs	Indirect	-	-	10,573,953	**10,573,953**
Total		**3,893,770**	**824,385**	**10,573,953**	**15,292,109**

[5] Includes all customer classes (Residential, Commercial, Industrial, and Institutional)
[6] Sum of net-present value of annual costs over the timeframe.

Table 5. Scenario 1B Benefits by Stakeholder Group (5-year horizon)

Benefit Category	Benefit Component	Benefit Type	Stakeholder Group					
			C&I ($)	Industrial ($)	Other[7] ($)	Residential ($)	Utility ($)	Total ($)
Operational Efficiencies	Customers' Utility Consumption, Billing and Generation Data Process Efficiencies	Direct	9,667,413	7,554	5,056,785	2,489,724	-	**17,221,476**
	Process Efficiencies (requirements)	Direct	12,063,383	80,564	-	-	-	**12,143,948**
	Reduced Customer Care Efforts	Indirect	-	-	-	-	1,029,360	**1,029,360**
	CDM/DSM Program Efficiencies and Innovation	Indirect	-	-	-	-	849,831	**849,831**
Energy Efficiency and Conservation	Increased Conservation - Behavioural & Operational	Indirect	9,243,371	13,761	-	1,564,616	-	**10,821,748**
	Increased Conservation - Retrofits	Indirect	19,031,618	73,190	-	5,616,971	-	**24,721,779**
	Total		**50,005,785**	**175,069**	**5,056,785**	**9,671,311**	**1,879,191**	**66,788,142**

[7] Other Stakeholders include third-party Energy Efficiency Consultants/Service Providers providing utility consumption monitoring services, energy assessments, and/or engineering services.

SCENARIO 2B: MULTI-INTEGRATED HOSTED DMD/CMD (ALL UTILITY TYPES)

Table 6. Scenario 2B Cost Details

Cost Category	Cost Type	5-Year Analysis ($)	10-Year Analysis ($)	Scenario-Specific Assumptions
Implementation (One-time setup and integration costs)	Direct	30,432,861	30,464,379	The setup cost for the Multi-Integrated scenario assumes: • 5 independent platforms for the electricity sector • 1 platform for the natural gas sector (because there are so few utilities) • 5 platforms for the water utilities
Operational Costs[8]	Direct	1,168,226	3,467,786	
Retrofit Costs	Indirect	12,578,686	71,377,618	
Total		**44,179,773**	**105,309,783**	

Table 7. Scenario 2B Benefits Details[9]

Benefit Category	Benefit Component	Benefit Type	5-Year Analysis ($)	10-Year Analysis ($)
Operational Efficiencies	Customers' Utility Consumption, Billing and Generation Data Process Efficiencies	Direct	24,054,230	71,046,545
	Process Efficiencies	Direct	14,167,939	27,644,897
	Reduced Customer Care Efforts	Indirect	1,559,328	3,412,449
	CDM/DSM Program Efficiencies and Innovation	Indirect	1,627,629	4,201,293
Energy Efficiency and Conservation	Increased Conservation - Behavioural & Operational	Indirect	13,340,724	64,123,022
	Increased Conservation - Retrofits	Indirect	25,395,815	123,019,789
	Total		**80,145,666**	**293,447,994**

RESULTS

DETAILED RESULTS FOR THE MULTI-INTEGRATED VERSION OF THIS SCENARIO (SCENARIO 2B) ARE PRESENTED IN THE FOLLOWING TABLES.

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[8] Sum of net-present value of annual costs over the timeframe.

[9] No scenario-specific assumptions required

Table 8. Scenario 2B Benefit-Cost Ratios

Ratio Type	5-Year Analysis	10-Year Analysis
Total	1.8	2.8
Direct Benefits and Costs only[10]	1.3	3.1

To illustrate how the costs and benefits are distributed across stakeholder groups, we present the following tables.

Table 9. Scenario 2B Costs by Stakeholder Group (5-year horizon)

Cost Category	Cost Type	Stakeholder Group				
		Electricity Utility ($)	Natural Gas Utility ($)	Water Utility ($)	Customers ($)	Total ($)
Implementation (One-time setup and integration costs)	Direct	3,458,565	524,157	26,450,138	-	**30,432,861**
Operational Costs[11]	Direct	435,205	300,228	432792	-	**1,168,226**
Retrofit Costs	Indirect	-	-	-	12,578,686	**12,578,686**
Total		**3,893,771**	**824,385**	**26,882,930**	**12,578,686**	**44,179,773**

[10] Direct benefits and costs are a subset of total benefits and costs. However, the direct benefits and costs *ratios* are higher than the total ratios because the magnitude of benefits to costs is different for direct results than for total results.

[11] Sum of net-present value of annual costs over the timeframe.

Table 10. Scenario 2B Benefits by Stakeholder Group (5-year horizon)

Benefit Category	Benefit Component	Benefit Type	Stakeholder Group					
			C&I ($)	Industrial ($)	Other ($)	Residential ($)	Utility ($)	Total ($)
Operational Efficiencies	Customers' Utility Consumption, Billing and Generation Data Process Efficiencies	Direct	11,708,323	9,443	9,576,590	2,759,875	-	**24,054,230**
	Process Efficiencies	Direct	14,073,947	93,992	-	-	-	**14,167,939**
	Reduced Customer Care Efforts	Indirect	-	-	-	-	1,559,328	**1,559,328**
	CDM/DSM Program Efficiencies and Innovation	Indirect	-	-	-	-	1,627,629	**1,627,629**
Energy Efficiency and Conservation	Increased Conservation - Behavioural & Operational	Indirect	11,758,678	17,431	-	1,564,616	-	**13,340,724**
	Increased Conservation - Retrofits	Indirect	19,031,618	73,190	-	6,291,008	-	**25,395,815**
	Total		**56,572,566**	**194,055**	**9,576,590**	**10,615,498**	**3,186,957**	**80,145,666**

DIRECT AND INDIRECT COSTS

The following table provides a breakout of direct and indirect benefits and costs for two key scenarios. We note that these costs are high level and used to generate comparisons between potential scenarios; they are not implementation-level cost estimates.

Table 11. Breakout of Direct and Indirect Benefits and Costs, Single and Multi-Integrated (10-year horizon)

10 Years	Single Integrated Hosted				Multi-Integrated Hosted			
	Benefits		Costs		Benefits		Costs	
	Direct	Indirect	Direct	Indirect	Direct	Indirect	Direct	Indirect
Electricity	$62,275,755	$136,049,865	$4,578,270	$50,137,048	$62,275,755	$136,049,865	$4,754,206	$50,137,048
Electricity and Natural Gas	$80,428,288	$173,834,221	$5,993,878	$60,072,210	$80,428,288	$173,834,221	$6,169,814	$60,072,210
Electricity, Natural Gas, and Water	$104,514,518	$188,933,476	$33,028,644	$71,377,618	$104,514,518	$188,933,476	$33,932,165	$71,377,618

ADDITIONAL COST-BENEFIT RATIO RESULTS FOR THE MULTI-INTEGRATED HOSTED SCENARIOS

The following table provides updated cost-benefit ratios for multi-integrated scenarios. Most of the results are the same as when a 2% discount rate is used, since the relative change in results is applied to both costs and benefits.

Table 12. Green Button DMD/CMD Multi-Integrated Scenario Cost-Benefit Results

Utility Type	5-Year	10-Year
Electricity	4.04	3.6
Electricity and Natural Gas	4.4	3.8
Electricity, Natural Gas, and Water	1.8	2.8
Natural Gas Component	6.1	4.9
Water Component	0.5	1.0

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Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-197

Date Request Received: 09/22/2020 **Date of Response: 10/02/2020**
Request No. STAFF 1-011 **Page 1 of 2**
Request from: New Hampshire Public Utilities Commission Staff

Witness: Christina S. Jamharian, Justin Eisfeller, Jeremy Haynes

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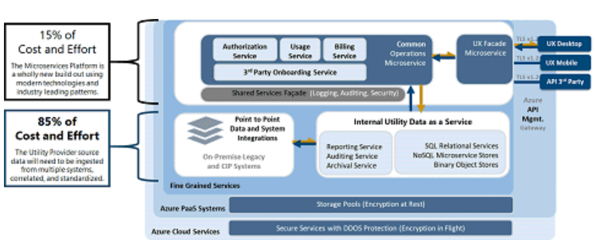
Request:
Reference Testimony at Page 19 of 20, Lines 4-7 stating "the most significant implementation costs will result from the work supporting the utility back-end integrations and the extraction and translation of the utility-specific data and data stores." For each utility:

a. Please elaborate on what activities are included in "Utility back-end integrations"?
b. Which of these specific activities related to utility back-end integrations are likely to result in the most substantial costs?
c. Are there certain data elements, particular types of customer data, and/or certain back-end data storage systems in which a particularly high integration cost is expected? Please explain why this is expected.
d. Which of these activities would be expected to be completed most cost-effectively by the Utilities, and which might be expected to be performed more cost-effectively by a contractor? Please explain why.
e. To what extent might these tasks need to be re-done if the proposed data platform were built and a utility were to subsequently adopt one or multiple new data management/storage systems in their bank-end? What proportion of the original implementation costs would likely need to be incurred again in such a case?

Response:
a. & b. The utilities will need to define the data required, identify the source of the data within the legacy utility systems and cloud data lakes, and build the processes to ingest data from those multiple systems. This includes storage, auditing, archival, and reporting services. The project team will need to review the tables defined in the GBC standard to determine which data elements will be provided, map those to source databases in the utility systems, and cross-check across the utilities to ensure the fields are being defined and used the same way. For example, the meter number may refer to a recording device or a pressure meter, a nameplate serial number or some other asset tag. Once the data is defined and developed, the interface will need to be built. At that point, the data is available to a third party.



c. Cost would be affected by the number of source systems or tables required and the time period involved. For example, system data is generally not tied to billing data, which would result in higher integration costs.

d. Eversource IT contracts with multiple vendors for development, testing, and other services for all capital projects and routine maintenance work.

The assignment of labor for this project, like any project the Unitil IT department has responsibility for, will need to be evaluated and decided in context. Resource availability, concurrent project load and a more concrete definition of the scope and requirements are all necessary inputs to this decision-making process.

The utilities believe that it will be necessary to be involved at some level with all aspects of the platform development, but it is reasonably safe to assume that the cost-effectiveness argument for utility internal labor is most compelling the closer we get to the source data. As the work becomes more abstract and standardized (for example at the API layer), it becomes less critical and likely less cost-effective for the utilities to do the work themselves.

e. The Eversource plan is to utilize our Azure cloud data analytics platform as the source of data for the statewide platform. As such, most data changes would not result in significant costs. Implementing AMI in NH could result in a major cost impact. Either the source could be changed to pull data from the AMI MDMS (meter data management system) or additional data and a much greater volume of data would be available in the Azure data lake. An estimation of cost would have to be developed at that point.

For Unitil, the introduction of any completely new data source into the platform will require some degree of mapping and integration work. The volume and cost of this work would be completely dependent on the specific data source being requests. Variables such as where this data resides in the utility backend architecture, what interfaces exist to this data, and what is the overall state of the data quality will all factor into the amount of time required to map and introduce a new source data system into the platform.

Liberty Utilities (EnergyNorth Natural Gas) Corp. and
Liberty Utilities (Granite State Electric) Corp. both d/b/a Liberty Utilities

DE 19-197
Development of a Statewide, Multi-Use Online Energy Data Platform

Staff Data Requests - Set 2

Date Request Received: 9/22/20 | Date of Response: 10/2/20
Request No. Staff 2-2 | Respondent: Heather Tebbetts

REQUEST:

Reference Liberty Utilities Response to Staff 1-3 stating "The current billing system, Cogsdale, can upload data to a Green Button Connect My Data platform. The new billing system is anticipated to be ready for use sometime in the second quarter of 2022." If a GBC-compliant statewide data platform were to be approved and customer data were successfully mapped and integrated to the statewide platform using Liberty's currently available data sources, before the implementation of the new billing system:

a. Which activities related to mapping, integrating, transforming, and extracting Liberty's data from its data sources to the statewide platform would likely need to be performed upon an eventual switch to the new SAP billing system? Please answer for both the electric and gas utilities and please explain why.

b. Which activities associated with mapping, integrating, transforming, and extracting Liberty's data from its data sources to the statewide platform would not need to be re-done upon a switch to the new SAP billing system? Please answer for both the electric and gas utilities and please explain why not.

c. Are there any activities associated with mapping, integration, transforming, extracting, and/or cleaning data that would likely need to be performed if Liberty's currently-available data sources are used to feed the statewide platform, as opposed to using the anticipated new data sources that will become accessible upon implementation of a new billing system and related data infrastructure? Please answer for both the electric and gas utilities and please explain why.

d. Please estimate the cost (As a quantified cost if possible, otherwise as a proportion of mapping/integration costs) of all activities related to mapping and integration that would likely need to be incurred upon a switch to the new SAP billing system. Please answer for both the electric and gas utilities.

RESPONSE:

a. SAP systems have the capability to export an XML file to data platforms like Green Button Connect. Liberty will be using this capability of the system to send the data to the statewide platform as part of its design for both gas and electric utilities. Because the current system already has this capability, there will not be a need for additional mapping, integrating, transforming, and extracting of data to accommodate the statewide platform.

b. Please see the response to part a.

c. The current platform Cogsdale has the capability to extract the data in XML format, but it is not currently designed to perform this function and any mapping, integration, transforming, extracting, or cleaning of data would be time consuming to design and extremely costly. Considering Liberty is in the process of designing the new billing system, trying to adapt Cogsdale to feed in to the statewide platform would be a waste of time and money.

d. The creation of the XML file to be sent to the statewide platform is part of the design of SAP, thus the cost of the activities for mapping and integration data for the platform can't be separately quantified.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 17-136

Date Request Received: 10/05/2018 **Date of Response: 10/19/2018**
Request No. OCA 2-010 **Page 1 of 2**
Request from: Office of Consumer Advocate

Witness: Katherine W. Peters

Request:
Reference 2018-20 Statewide Energy Efficiency Plan Settlement Agreement, Page 7-8, which states "In the event that marketing efforts carried out during the first six-months of 2018 do not result in comparable increases in customer access to the platform as achieved and recently reported by Eversource for the CEP in Connecticut and Massachusetts, any of the Settling Parties may propose alternative strategies."

a. Is the Customer Engagement Platform provided to Eversource by an external vendor as a software-as-a-service (SaaS) tool?
b. Does Eversource earn a rate of return on any aspect of the Customer Engagement Platform?
c. Please provide the number of unique hits the Customer Engagement Platform site has experienced during the first six months of 2018.
d. Please provide a comparison of the number of unique hits over time in New Hampshire compared to the increases "recently reported" in Connecticut and Massachusetts.
e. Please describe the funding source for the Customer Engagement Platform at each of the Company's affiliates in Massachusetts and Connecticut, the annual budget, and the overall cost to date.

Response:

a.) Yes, the Customer Engagement Platform (CEP) is supported by an external vendor as a software-as-a-service (SaaS) tool.

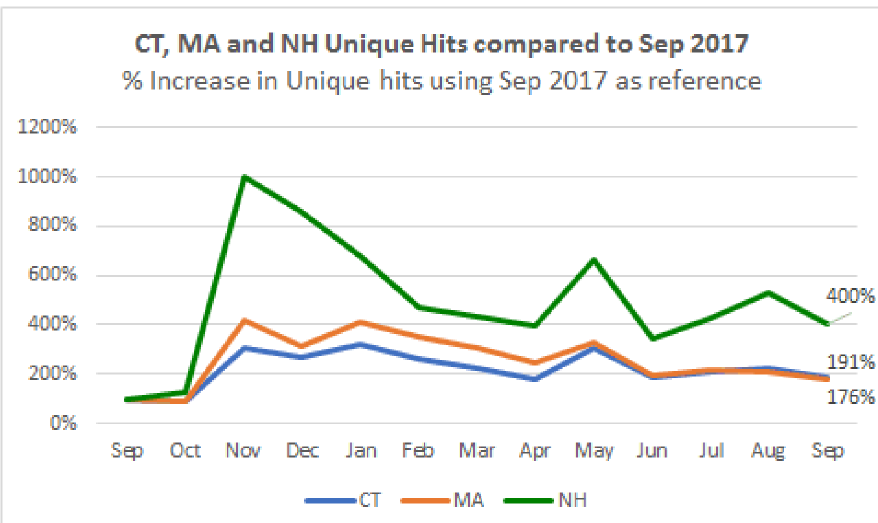
b.) Eversource invested $3 million in IT costs to develop the infrastructure to support the Customer Engagement Platform, and for this portion, Eversource receives cost recovery plus weighted average cost of capital. The balance of cost is recovered from the Energy Efficiency program budget (i.e. License fees, maintenance). The spending from energy efficiency programs is incorporated into the energy efficiency performance incentive calculation for that state.

c.) The chart below shows the total traffic CEP received during the first half of the year, including both new users and repeat visitors for NH.

	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18
CEP Visitors - NH	915	632	583	533	898	459

d.) The chart below show hits CEP got between September 2017 and September 2018 for all three states. For context, there are 1.2 million customers in Connecticut, 1.4 million customers in Massachusetts and 510,000 customers in New Hampshire. The graphic below compares the percent increase in unique hits, using September 2017 as a reference, for each state during the past 12 months.

	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18
CT	676	617	2089	1808	2170	1762	1528	1214	2079	1268	1391	1515	1289
MA	576	528	2404	1812	2377	2013	1749	1438	1892	1099	1261	1204	1014
NH	135	175	1347	1161	915	632	583	533	898	459	577	713	540



e.) The CEP is funded by the energy efficiency programs in all three states. The primary funding sources for Connecticut's energy efficiency programs are: 1) The three-mill systems benefit charge on customer electric bills; 2) The Conservation Adjustment Mechanism ("CAM") less gross receipts tax ("GRT") assessed on customer electric bills; and 3) Contributions from natural gas customers (on firm rates) through the natural gas CAM.

The primary funding sources for Massachusetts's energy efficiency programs are:
1) revenues collected from ratepayers through the SBC; 2) proceeds from the Program Administrators' participation in the FCM; 3) proceeds from cap and trade pollution control programs, including but not limited to the RGGI; and 4) other funding as approved by the Department, including revenues to be recovered from ratepayers through a fully reconciling funding mechanism (i.e., an EES).

The combined annual budget for CEP in 2018 is $4,642,648, (NH portion $529,692) which includes license fee, marketing, and IT cost etc. Overall cost since inception to date is $22,966,929 (NH portion $1,360,287.50).

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-197

Date Request Received: 09/22/2020 **Date of Response: 10/02/2020**
Request No. STAFF 1-024 **Page 1 of 1**
Request from: New Hampshire Public Utilities Commission Staff

Witness: Christine Riley Hastings, Justin Eisfeller

Request:
Reference Testimony at Page 50 of 55 describing a governance model including an Operations Committee.

a. Please describe which responsibilities of the proposed Operations Committee would need approval from the Governance Working Group and/or Commission via semi-annual proposals and why.
b. Please describe which responsibilities would be entirely under the authority of the Operations Committee and why.

Response:

a. The Operations Committee (OC) would need approval of the Governance Working Group (GWG) for draft or revised operating policies and procedures; platform scoping and pricing changes; operating and capital budget revisions; and final decisions on security restrictions on users of the platform. The OC and GWG would need approval of the Commission on governance changes, and operating and capital budget approvals, as those items relate to the core mandate of the Commission's authority.

b. The Operations Committee (OC) would make decisions on day-to-day operations and security including short term restrictions on platform access due to immediate cyber concerns; platform change management categorization (there is an expectation that change management approvals will vary with change complexity and risk); and cyber event classification and incident response. The OC would also be responsible for making technical design decisions where the decision affects the operations or security of the platform.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-197

Date Request Received: 09/22/2020 **Date of Response: 10/02/2020**
Request No. STAFF 1-017 **Page 1 of 1**
Request from: New Hampshire Public Utilities Commission Staff

Witness: Christine Riley Hastings, Jeremy Haynes

Request:
Reference Testimony at Page 29 and 30 of 55 describing "Option 3" for the data platform and stating "The additional development and management required of these convenience features increases the cost and scope of the platform; substantially."

a. Please explain which of the additional features included in Option 3, but not in Option 2, would "substantially" increase the cost of the platform and why. Please address each individually and please provide an estimate of the cost increase related to each if possible:
   i. "API of APIs;"
   ii. Centralized Web Portal that provides combined and aggregated data by municipality; and
   iii. Provide limited forms of system level data.
b. For each of these features, is it expected that such a feature could be added on to an "Option 2" platform at a later time? Would the cost of adding these features at a later time be similar to originally incorporating them into the platform? Please explain why or why not.
c. Might the optimally cost-effective back-end data integration solutions be different depending on whether the platform is specified to include an "API of APIs", a centralized data warehouse, a centralize web portal, and/or none of these? Please explain why or why not.

Response:

a. Each of the above has the potential to "substantially" increase cost, due to what the Utilities have estimated would be the necessary level of effort in order to include each of those elements. We do not have estimates of the cost increase of any of these at this time. Providing such estimates could be made possible by a Commission Order or RFI (as discussed in page 53 of our joint direct testimony) outlining at least cursory scope and design components of the platform so that the incremental costs could be calculated in context – as such incremental costs can vary depending on the core design of the platform.

b. The intention of the conceptual design is to facilitate incremental changes to the system based on cost-benefit analysis. This allows the parties to evaluate how the system is being used before investing in new features. Additional features, defined in option 3 and/or others, would not be significantly impacted by implementing the changes in increments over time. In fact, it would reduce both risk and cost by ensuring what is implemented is truly what is needed.

c. No. The data must still be pulled from the utility systems in a defined format. A centralized data warehouse would increase the cost of the solution exponentially. It would generate costs for code and data storage, cyber security, system management, data retention, code management, and the labor associated with each of these as well. A centralized web portal for managing third party requests and possibly customer authorization, as discussed for Option 3, would be an additional cost that should be evaluated based on the use of the service and the benefit it could potentially provide.

DE 19-197 Public Utilities Commission Staff

OCA Responses to Staff Set 1

Date Request Received: 8/31/20 **Date of Response: 9/21//20**
Request Number: Staff 1-11 **Page 1 of 1**
Witness: James Brennan

Data Request:

Reference Testimony at Page 96 of 153 describing a proposed design pilot.

a. Please describe what tasks described in this Design Pilot are additional tasks which would not otherwise be performed if the Statewide Data Platform was designed and implemented without such a pilot.
b. Please explain whether these tasks represent additional costs which would not otherwise be incurred? If so, please provide an estimate of what any such additional tasks would cost.
c. If possible, please provide an estimate of the cost of the entire pilot, as described in this section and as depicted in Figure 11 on Page 94 of your testimony.
d. Do you suggest that a vendor is used for some or all of the tasks of this pilot? If so, should such a vendor be solicited by an RFP?

Data Response:

a. Neither the Design Pilot nor the Statewide Data Platform have project plans documenting resources and project tasks to be performed. Therefore I am unable to identify the "additional tasks that would not otherwise be performed."
b. See response to (a) above.
c. For reasons stated in (a) it is not possible to provide an estimate. In my opinion, and without having researched many variables, and without knowledge or consideration of the final negotiated pilot strategy, including duration and resources, a meaningful valuable pilot could be run with a budget range of moderate five figures to moderate six figures, give or take variances due to a multitude of factors unknown as of now.
d. Please refer to Bates page 100 lines 1-9 of my testimony and my response OCA 01-05.

CASE 20-M-0082 – In the Matter of Strategic Use of Energy Related Data

DEPARTMENT OF PUBLIC SERVICE STAFF WHITEPAPER
REGARDING A DATA ACCESS FRAMEWORK

Dated May 29, 2020

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1. The Path Forward – Statewide Data Access Framework

Increasing the availability of, and appropriate access to, system and customer energy usage data, has long been a priority of the Public Service Commission (Commission). Useful access to useful energy-related data is key to implementing REV[1] and the Governor's clean energy policies. While the ability of market participants to deliver smart economically sound energy solutions to meet New York's clean energy goals depends on their ability to obtain access to useful data, it is critical to protect information technology (IT) and data systems against cyber and other risks, to ensure the protection of customers' privacy, especially as relates to sensitive data, and to preserve customer control over his or her energy usage data (as the owners of the data) including control over access to that data, based on consent. This whitepaper and this proceeding will lay out approaches that serve the principle of useful access to useful energy-related data while simultaneously ensuring that cybersecurity requirements are followed and customer privacy is protected.

Data-related topics have been addressed across numerous Commission proceedings in recent years. In its Accelerated EE Order,[2] for example, the Commission, announced that a new, comprehensive data proceeding would be instituted. The Commission established guiding principles to serve as foundational elements for developing policies that appropriately balance privacy concerns with the rapidly changing energy marketplace, including: (1) increasing customers' familiarity with, and consent to, appropriate data sharing; (2) a movement towards improved access by an Energy Service Entity (ESE) to customer energy-related data, consistent with consent;[3] (3) linking energy-related data with other sources of building data, energy use drivers, and energy systems data to enable enhanced identification of Energy Efficiency/ Distributed Energy Resource (DER) opportunities; and (4) ensuring that the mechanisms for appropriate access to energy-related data are implemented in a useful, timely, and quality-assured manner.

The Commission in its *Order Instituting Proceeding*, issued March 19, 2020 in this case, reinforced its view that existing requirements related to data access are inconsistently applied and lack clarity.[4] The Commission therefore directed the establishment of a "Data Access Framework" that clearly defines the process for access to customer energy-related data and standardizes the necessary privacy, cybersecurity, and quality requirements for data access to ensure uniform treatment across various

1 Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, (issued April 24, 2014) (REV).

2 Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative, Order Adopting Accelerated Energy Efficiency Targets (Issued December 13, 2018) (Accelerated EE Order).

3 Any entity (including, but not limited to, ESCOs, DERs, and CCA Administrators) seeking access to energy related data. In limited circumstances, the utility may also be an ESE.

4 Case 20-M-0082, Proceeding on Motion of the Commission Regarding Strategic Use of Energy Related Data, Order Instituting Proceeding (issued March 19, 2020).

energy-related data use cases. In addition, the Commission stated that the Data Access Framework shall include the development of metrics regarding quality and accuracy of energy-related data. It directed Staff of the Department of Public Service (Staff) to, within 60 days of the date of the Order, file a whitepaper consistent with the objectives stated above.

As proposed by Staff, the Data Access Framework would serve as a single source for data access policies and provides uniform and consistent guidance on what is needed for access to, and the availability of, energy-related data. In addition, the proposed Data Access Framework would provide a more workable approach that is designed to provide access to data, while preserving all the necessary protections, to fully enable the intentions of the Commission.

To accomplish these outcomes, the proposed Data Access Framework endorses the risk-based approach to managing the cybersecurity and privacy risks associated with allowing access to energy-related data. Adoption of a risk-based approach would provide a standardized process, along with specified requirements defined by the access and data type, while still ensuring the necessary protections are in place. The proposed Data Access Framework also recognizes the customer's right to access and share his or her data and enables useful access to useful energy-related data by ESEs. In order to fully optimize the benefits of useful access to data, customers must be made aware of their rights to control and share their energy-related data in the simplest and most seamless manner. Customers should be enabled to understand the true value of their data and how a simple act of informed consent correlates directly to meeting their own interests and those of the State. This whitepaper includes a proposal to develop a customer consent mechanism that facilitates a customer's ability to easily consent to share useful energy data in a manner that protects personal privacy.

To ensure that ESEs seeking access to energy-related data have instituted the necessary cybersecurity and privacy protections, the proposal includes implementation of an ESE risk management program that would provide certification of an ESE's readiness to access data. The proposed Data Ready Certification process: (i) includes verification that the ESE is authorized by the Department of Public Service (DPS or Department); (ii) requires the ESE to detail access consideration information - purpose, transmittal mechanism, and data sets; and (iii) validates that the appropriate cybersecurity and privacy requirements are in place by relying on a charting of the existing cybersecurity and privacy requirements and how they apply to the various combinations of purpose, access mechanism, and data. Creation of such a cybersecurity and privacy requirement matrix requires a detailed examination of all existing requirements, accounting for duplicative and inconsistent requirements, and evaluation of correct risk assignment. Once an ESE is certified as "Data Ready," the ESE can request access to data from any data custodian, without having to access each data custodian's process. Certification as Data Ready enables the data custodian to efficiently determine the data an ESE has been certified to access, and by what means. The Data Ready certification has the potential to speed up the ESE verification process, enable access to data in a manner that assures the ESE has the necessary protections in place, and provide a consistent understanding and implementation of the Data Access Framework.

In Summary, this whitepaper details a proposed Data Access Framework that:

- Provides standard definitions of key data-related terms.
- Provides a consistent path to harmonizing existing approaches that have arisen in multiple contexts and Commission proceedings, while also improving achievement of the goals of useful and protective access to useful energy data.
- Identifies the rules, roles, and responsibilities for parties seeking access to energy-related data and ensures uniform treatment of energy data access requests, regardless of where the data are being housed, which provides certainty to customers, utilities, and ESEs.
- Is foundational in that an ESE must be deemed suitable before it can be granted access to energy-related data. To be deemed suitable, an entity would need to satisfy the necessary DPS requirements to become an authorized ESE that is able to request access energy usage data.
- Requires that requests for access to energy data must be proper with regard to purpose, transmittal, and data sets. In this regard, the whitepaper differentiates between categories of data as follows:
    - Highly confidential personal information, as defined in this whitepaper, and similarly sensitive data, should never be shared.
    - Other data, which is enumerated in this whitepaper, is appropriate to share – upon consent or Commission Order, State, Federal, and Local Laws or regulation.
    - Anonymized data presents far fewer privacy concerns and thus fewer requirements for consent.
- Supports the findings in the Commission's Cybersecurity Order,[5] including that the necessary cybersecurity and privacy protections must be commensurate to the risk associated with the data being shared and the way it is being accessed. In this respect, the whitepaper proposes:
    - Consolidation of existing cybersecurity and privacy protections into a matrix that determines the appropriate requirements based upon the risk presented.
    - A proposed Data Ready Certification program to confirm the ESE has implemented the appropriate requirements.
- Gives practical meaning to customer control of energy-related data and recognizes that customers need simple, practical, yet still protective approaches to granting informed consent.
- Recognizes that access to data is moot without assurance of quality, integrity, and timeliness of the data when provided by a utility or other data custodian.

[5] Case 18-M-0376, Proceeding on Motion of the Commission Regarding Cybersecurity Protocols and Protections in the Energy Market Place, Order Establishing Minimum Cybersecurity and Privacy Protections and Making Other Findings (Issued October 17, 2019) (Cybersecurity Order).

- Creates an easy to understand *Data Access Framework Application Guide* that outlines the necessary steps to obtain access to energy-related data in a uniform and consistent manner.

2. Useful Access to Useful Energy Data – Actions and Outcomes

The Commission has taken many actions to enable access to energy-related data. Based on Staff's review, however, the ESE's ability to gain access to customer and system data remains inhibited predominantly due to unclear access requirements, data quality and integrity, and cybersecurity and privacy concerns. Some of these programs were adopted prior to advancements in computer-based technologies, while others were adopted with the sole focus on the risks inherent in the simple transfer of information via IT systems. The process by which the Commission has adopted the policies, however, has resulted in a piecemeal approach to the addressing these data access issues. The proposed Data Access Framework in this whitepaper would incorporate existing Commission-established data access policies and requirements to create a universal statewide data access process that enables useful access to useful data while still preserving protection of IT systems and the data they house.

2.1. Enabling Access to Data

REV Track 1 and Track 2 Orders

Approximately five years ago, the Commission recognized in its REV Track 1 Order that effective DER markets required a framework that enables customers and third parties to become active participants in the planning, management and operation of the electric system.[6] The Commission understood that, to incentivize effective DER markets, utilities would need to revolutionize their communication and data management capabilities. Accordingly, the REV Track 1 Order required each utility, as the Distributed System Platform (DSP), to file a Distribution System Implementation Plan (DSIP).

The Commission reiterated in its REV Track 2 Order that ready access to information regarding customer energy usage is vital to the success of the DER market.[7] The Commission specified that a utility's satisfactory performance of its DSP function would rely in part on its success in facilitating customer engagement regarding access to data and connecting customers with ESEs.

[6] Case 14-M-0101, supra, Order Adopting Regulatory Policy Data access policy and Implementation Plan (issued February 26,2015) (REV Track 1 Order).

[7] Case 14-M-0101, supra, Order Adopting a Ratemaking and Utility Revenues Model Policy Data access policy (issued May 19, 2016) (REV Track 2 Order).

Distributed System Implementation Plans

In April 2016, the Commission adopted the DSIP Guidance Order, which provided greater detail with respect to the DSIP filing process and the contents of the DSIP filings pertaining to both customer and system data.[8] The utilities' subsequent biennial DSIP filings describe their current status and future plans for timely and efficient sharing of useful data.

With respect to customer data access, the DSIP Guidance Order required each utility with Advanced Metering Infrastructure (AMI) deployment plans to submit a proposed implementation plan, budget, and timeline for implementing Green Button Connect (GBC) or an alternate standard that offers similar functionality.[9] The Commission directed the utilities without AMI deployment plans to identify other tools that could be used to enable customer and authorized third-party access to customer data, as well as implementation plans, budgets, and timelines. The Commission also encouraged utilities to include GBC implementation plans for rolling out AMI.

Staff provided the utilities with more detailed DSIP guidance in a May 2018 whitepaper,[10] further emphasizing the importance of customer and distribution system data, stating that, "maintaining a full and timely exchange of DSIP information between the utilities and market participants is critical to achieving the most beneficial deployment and use of DERs. Key areas of emphasis should include: the purposeful development of market participant tools and information sources useful to DER providers in fostering productive DER development; collecting, managing, and sharing system and customer data; and, advances toward an integrated planning environment."

Green Button Connect Implementation

The Commission again addressed GBC within the Accelerated EE Order,[11] in which it recognized that irrespective of the fact that the rollout of AMI is not expected to be completed for several more years, utilities should try to include GBC implementation plans in their DSIPs, as well as AMI rollout plans. The Accelerated EE Order noted that monthly customer usage, available with current metering, is useful to

[8] Case 16-M-0411, In the Matter of Distributed System Implementation Plans, Order Adopting Distributed System Implementation Plan Guidance (issued April 20, 2016) (DSIP Guidance Order).

[9] Green Button Connect (GBC) is a widely recognized and well-accepted method of providing customers access to their energy usage data and enabling customers to consent to the provision of their energy consumption data to one or more third parties.

[10] Case 16-M-0411, supra, DPS Staff Whitepaper, Guidance for 2018 DSIP Updates (filed May 24,2018) (2018 DSIP Guidance).

[11] Case 18-M-0084, supra, Order Adopting Accelerated Energy Efficiency Targets (Issued December 13, 2018) (Accelerated EE Order).

potential ESEs, and directed utilities to expedite their implementation of GBC to enable ESEs to gain access to customers' monthly data.

Despite the Commission's direction to expedite the implementation of GBC, to date only Consolidated Edison Company of New York, Inc. (Con Edison) and Orange & Rockland Utilities, Inc. (O&R) have fully implemented GBC. As reported within the Joint Utilities' October 16, 2019 Status Report on Green Button Connect My Data,[12] even within these two utilities, only three ESEs have been able to successfully complete the necessary steps of the onboarding process allowing them to receive customer data and be identified as an available ESE with whom customers can consent to share their data. Additionally, one of the three ESEs that completed the process asserted that they were unable to utilize GBC because the utility implementation of GBC was not developed consistent with the GBC Standard. For its part, Con Edison reported that, from the time period between April to October 2019, only 362 of its customers had shared data via GBC.[13] The small number of onboarded ESEs and customers who have utilized GBC to date demonstrates that Con Edison's and O&R's GBC implementation have not produced the anticipated benefits.

In sum, inconsistent GBC implementation by the utilities, ESE onboarding problems, and the lack of ease for a customer to find and use GBC have resulted in GBC being utilized at rates far below what the Commission envisioned in the DSIP Guidance and Accelerated EE Orders.

Community Choice Aggregation

CCA programs allow municipalities to procure energy supply services and DER products for eligible energy customers in their communities. By pooling demand, communities aggregate the load necessary to negotiate a supply contract with private suppliers. To commence a CCA, a CCA Administrator must receive three different types of data from the utility - aggregated data, customer contact information,

[12] The Joint Utilities' October 16, 2019, Updated Joint Utility Green Button Connect Report provides the following status of each utilities GBC Implementation. Con Edison and O&R launched GBC on December 19, 2017, and the first ESE was successfully onboarded on December 12, 1018. Their customers can currently share their energy data with three ESEs, with ten additional ESEs in various stages of the onboarding process. Central Hudson Gas & Electric Corporation (Central Hudson) does not offer GBC but offers Green Button Download My Data. Niagara Mohawk Power Corporation d/b/a National Grid (National Grid) is currently planning to implement GBC for its electric and gas customers by March 31, 2021. New York State Electric & Gas Corporation (NYSEG) allowed customers to use GBC using a third-party vendor as part of its Energy Smart Community (ESC) Energy Manager pilot. Customers in the ESC were temporarily able to use GBC to share energy usage data with six approved ESEs. NYSEG and Rochester Gas and Electric Corporation's (RG&E) full implementation of GBC as part of their Energy Manager Web Portal is subject to the Commission's approval of the Companies' AMI proposal in their ongoing rate proceeding in Cases 19-E-0378 et al.

[13] Case 16-E-0060 et al., AMI Metrics Report (filed October 31, 2019).

and detailed customer usage data. These datasets must be transferred to a CCA from the utility before a CCA can begin to supply energy to its members. Utilities are responsible to transfer the aggregated customer and usage data within twenty days of a request from the municipality or the CCA Administrator. At this time, the 15/15 privacy screen is applied to the CCA aggregated data.[14] After each municipality has entered into a CCA contract with an Energy Service Company (ESCO), the utility transfers the customer-specific data to the municipality or CCA Administrator within five days of a request to support the mailing of opt-out notices. After the opt-out period has ended, the municipality or the ESCO may submit a request to the utility for detailed customer data, including energy usage data, for customers consistent with existing Electronic Data Interchange (EDI) protocols.

CCA Administrators continue to notify Staff of data access problems they encounter with utilities, including the failure to provide data within the Commission adopted timeframes, the inaccuracy and inconsistency of the data, and problems with the privacy screens. Understanding that the Commission adopted the CCA program only a few years ago and that some utilities are unaccustomed to this type of data compilation, Staff has been working with both CCA Administrators and utilities to resolve these data issues.

Utility Energy Registry

On April 20, 2018, the Commission issued an Order approving the development and implementation of the Utility Energy Registry (UER).[15] The UER is an online public platform developed and maintained by the New York State Energy Research and Development Authority (NYSERDA), with the support of the investor-owned gas and electric distribution utilities, to provide streamlined public access to aggregated community-scale utility energy data.[16] The UER, as authorized in the UER Order, was a starting point to require continuing Commission oversight and refinement and was understood as a platform that would evolve over time.

Semiannually, utilities report monthly aggregated data that populates maps of municipalities and counties statewide, and zip codes in the New York City metropolitan area. Following additional privacy standards adopted by the Commission in the UER Order, utilities withhold data in locations with limited

[14] By the DSIP Order, the Commission adopted a 15/15 standard for aggregated data set use cases which established that an aggregated data set may be shared only if it contains at least 15 customers, with no single customer representing more than 15 percent of the total load for the group and adopted a whole building energy data aggregation standard of 4/50 that established an aggregated data set may be shared only if it contains at least 4 customers, with no single customer representing more than 50 percent of the total load for the group.

[15] Case 17-M-0315, In the Matter of the Utility Energy Registry, Order Adopting Utility Energy Registry (issued April 20, 2018) (UER Order).

[16] Available at: https://utilityregistry.org.

numbers of customers to protect consumer privacy.[17] The UER now contains four years (2016-2019) of monthly electricity and natural gas data for 1,300+ municipalities. The public can visualize data and download it in Comma Separated Values (CSV) format. All data are associated with a Census code so communities can look at energy performance against demographic drivers.

On December 30, 2019, NYSERDA filed a UER Status Report (Report) prepared by Climate Action Associates, LLC to report on the progress of the UER's implementation and operation, including the demand for, and uses and benefits of UER data, as well as the need for refinements.[18] Some of the proposed modifications within the Report include restructuring the existing data fields and increasing access to data by recommending modification to the privacy screen to rely solely on a customer count. The Commission is expected to act on the recommendations contained within the Report in a future order.

Building Benchmarking

The Accelerated EE Order recognized benchmarking of building energy performance as an important market enabling mechanism to provide energy users information about how their consumption compares with peer buildings. New York City began requiring benchmarking and disclosure of energy and water usage in 2009 through Local Law 84, and cities in other states have also implemented this requirement.[19] Local Law 84 requires utilities serving New York City to establish systems and processes to electronically provide aggregated metered consumption data for all electric and gas accounts by building to support automated upload to the Energy Star Portfolio Manager.

Given the experience of the downstate utilities, the Commission recognized that the upstate utilities should assess their readiness to support eventual statewide benchmarking. Specifically, the Accelerated EE Order requires the utilities to, upon building owner request, provide aggregated whole building electric and/or gas meter data for any given building or tax lot to an owner, subject to the 4/50 privacy screen established by the Commission, for use in benchmarking through the Energy Star Portfolio Manager. The Accelerated EE Order also requires the utilities to develop the capability to automate the uploading of aggregated data and, in consultation with NYSERDA, a programmatic offering that utilizes benchmarking data to be marketed to decision-makers of suitable building types.

As of 2019, Con Edison, National Grid, KeySpan Gas East Corp. d/b/a National Grid (KEDLI), and Brooklyn Union Gas Company d/b/a National Grid (KEDNY) are the only utilities to have automated upload

[17] Utilities withhold sector data to protect consumer privacy if it fails a count/magnitude screen. The residential sector screen is 15/15. If there are less than 15 accounts, or if one account is more than 15% of the total, the entire sector is withheld. The screen for non-residential sectors is 6/40.

[18] Case 17-M-0315, supra, NYSERDA UER Status Report, (filed December 30,2019).

[19] New York City Local Law 84 of 2009.

capabilities of monthly aggregated whole building data. NYSEG, RG&E, and Central Hudson have each initiated the system integration to be able to provide automated upload capabilities, a process they believe will be completed within the next two years. O&R and National Fuel Gas Distribution Corporation (NFG) have not yet initiated the implementation process to develop the IT capabilities to provide automated upload functionality but are expected to do so in the near term. Regarding programmatic offerings, NYSERDA, along with select utilities, continue to meet with Staff to discuss what would be needed within a successful programmatic offering and are taking steps to identify specific program components.

Utility System Data

Since 2016, each regulated electric utility in New York State has separately implemented, enhanced, expanded, and maintained one or more online portals for sharing useful electric system information with ESEs and other industry market participants. The types and attributes of shared information, and the methods for sharing the information, have been both prescribed directly by the Commission and determined through a Commission-directed market participant engagement process that is led by the Joint Utilities of New York (JU).

The categories of system information currently available online for each utility are as follows:

- Distributed System Implementation Plans (via the DPS Document Matter Management System (DMM)).
- Capital Investment Plans (via the JU web site or the DPS DMM).
- Planned Resiliency/Reliability Projects (via the JU web site or the DPS DMM).
- System Reliability Statistics (via the utility's web sites or the DPS DMM).
- Hosting Capacity (via the individual utility web sites).
- Beneficial Locations for DERs (partially available via the individual utility web sites, the JU web site, or the DPS DMM).
- System Load Forecasts (partially available via the individual utility web sites).
- Historical System Load Data (partially available via the individual utility web sites).
- Opportunities for Non-Wires Alternatives (partially available via the individual utility web sites).
- Distributed Generation Queued for Interconnection (via the DPS web site).
- Installed Distributed Generation (via the DPS web site).
- System Interconnection Request (SIR) Pre-Application Info (via the individual utility web sites).

The system data needed to support innovation and efficiency is not available in the way it was intended. Web links to all the utilities' online system information sources are publicly accessible via the System

Data page of the JU web site.[20] However, the structure, attributes, semantics, availability, and accessibility of the information from many of these sources vary significantly across the utilities. In addition, these sources provide very little of the information related to electric vehicle loads and energy storage as advised in Staff's 2018 DSIP Guidance. Finally, and very importantly, only the few sources pertaining to DER interconnections provide any sort of association between a utility customer and the system infrastructure that serves that customer.

Date Access Fees

The REV Track 2 Order set forth the conditions under which utilities may charge for data that is more granular and/or is requested on a more frequent basis than basic individual customer usage data. The Commission agreed that certain basic levels of information will be free of charge to customers and vendors authorized by the customer, while utilities could charge a fee for provision of more refined data or analysis, such as aggregated data. The Commission understood that the development of providing aggregated data would impose costs on utilities until fully automated systems were developed.

In the CCA Framework Order, the Commissioner permitted utilities to charge a fee for access to aggregated community load data, as well as the customer information needed to facilitate opt-out mailings.[21] In December 2017, the Commission established a uniform fee, for all utilities, of $.80 per account.[22] The fee was apportioned 20% to requests to utilities for aggregated data and 80% to request to utilities for customer lists. CCA Administrators have been paying the data access fees, and complying with all other requirements for data access. However, as previously mentioned, there are significant lag times for receiving the data and questionable quality and accuracy of the data.

In summary, the Commission's actions meant to empower customers' right to share their data and enable market offerings, such as GBC adoption and the data-sharing achievements and plans reported in the DSIPs to-date, have not been successful to this point and have fallen well short of Commission expectations. Avenues for access to system data remain limited and inconsistent between what is available and the paths available for access to that data.

[20] Available at: https://jointutilitiesofny.org/system-data/.

[21] Case 14-M-0224, Proceeding on Motion of the Commission to Enable Community Choice Aggregation Programs, Order Authorizing Framework for Community Choice Aggregation Opt-Out Program (issued April 21, 2016) (CCA Framework Order).

[22] Case 17-M-0315, et al., Order Establishing Community Choice Data Access Fees (issued December 14, 2017).

2.2. The Evolution of Data Access Requirements

The Commission has developed a series of requirement to enable access to energy related date, including those related to cybersecurity and privacy protections, as well as registration requirements. Those requirements and related policies are summarized below.

Uniform Business Practices (UBP)

ESCO UPB

In February 1999, the Commission adopted the Uniform Business Practices (UBP), to provide for consistent business procedures for both ESCOs and electric and natural gas utilities across the state.[23] As the competitive retail energy market has evolved in New York, the UBP has been revisited and modified to reflect changes in the market while continuing to provide consumer protections, streamlined business transactions, and communications protocols between ESCOs and utilities. The ESCO UBP is a comprehensive document that details the requirements and obligations of ESCOs providing service in New York State. It includes information that can be categorized into two main topics: ESCO operation requirements; and ESCO customer requirements. The customer requirements include, among other things, marketing standards and customer data protections.[24]

DER UBP

As part of the REV initiative, the Commission initiated a proceeding to consider the regulation and oversight of DER providers and products.[25] The Commission's experience in regulating ESCOs in the gas and electric supply market demonstrated that DER oversight is required to ensure that customers participating in DER markets and programs understand the costs and benefits of their investments and are protected from confusion, fraud, and abusive marketing practices. The Commission realized that clear, consistent rules and uniform marketing and contracting practices are needed to, among other things, prevent exploitive pricing and deceptive marketing practices to residential and small business customers, ensure that customers and DER suppliers know their rights and responsibilities, and provide oversight tools needed to monitor the growing markets and resolve potential conflicts.

The ESCO UBP and DER UBP (UBPs) have been a necessary, and integral, part of the regulation and oversight of ESCOs and DERs participating in NY markets. Since their inception, the UBPs have been modified to keep pace with market changes. Up to this point, attempts to modify the ESCO UBP have taken an extended amount of time. In particular, changes to the customer requirements have often been delayed due to market participant challenges to the proposed changes of operation requirements.

23 Case 98-M-1343, Retail Access Business Rules, Opinion NO. 99-3, Opinion and Order Concerning Uniform Business Practices (issued February 16, 1999).

24 UBP ESCO, Section 4.

25 Case 15-M-0180, In the Matter of Regulation and Oversight of Distributed Energy Resource Providers and Products.

This delay, in turn, has hampered the Commission's ability to ensure the appropriate customer protections are in place in the context of fast-paced changes in the ESCO and DER markets.

CCA Data Security Agreement

Per the CCA Framework Order,[26] a Data Security Agreement (DSA) is required to be signed by the CCA Administrator, and possibly other parties, before any data can be requested or received for establishing a CCA program. The CCA DSA was a starting point for the development of the ESS DSA that was implemented and required by the utilities for ESEs seeking access to customer-related data.

Cybersecurity and Privacy Protections

The Cybersecurity Order adopted a minimum level of cybersecurity and data privacy requirements for companies that electronically receive and exchange utility housed customer data with the utilities' IT systems, and ensured privacy requirements were in place for those who received customer energy-related data through any means. These protections included requirements from the previously developed DSA and Self-Attestation. The Self-Attestation consists of a 16-point inventory of cybersecurity controls based upon the National Institute of Standards and Technology (NIST) Cybersecurity Framework listing of risk mitigation controls.[27] The contents of the Self-Attestation and DSA were developed by the JU, Staff, and the ESEs in a collaborative, business-to-business process.

These cybersecurity and data privacy requirements provided a universal foundation of protections and ensured the privacy of customer data and protection of the utility IT systems, all while enabling and encouraging data access. The Cybersecurity Order also recognized that there may be certain entities that would be unable to agree to these requirements but would still need access to energy-related data (e.g., New York Power Authority (NYPA) and the State University of New York (SUNY)). The Cybersecurity Order thus allowed for these entities to work with the utilities in modifying the agreement in a way that still ensured the necessary protections were maintained. The baseline cybersecurity and privacy requirements were adopted from the DSAs that were in use by the utilities, which had been based upon the JU-developed Cybersecurity and Data Privacy Risk Strategy.[28]

The Cybersecurity Order recognized that the data belongs to the customer and that customers have a right to direct or consent to the use of that data. The Cybersecurity Order also recognized that it is not

[26] Case 14-M-0224, Proceeding on Motion of the Commission to Enable Community Choice Aggregation Programs, Order Authorizing Framework for Community Choice Aggregation Opt-Out Program (issued April 21, 2016).

[27] The utilities identified these requirements as being necessary under NIST Special Publication 800-53.

[28] Case 16-M-0411, supra, Joint Utility Supplemental Distributed System Implementation Plan, (filed November 1,2016) (Supplemental DSIP).

the utilities' business model to audit ESE cybersecurity and privacy programs or to determine compliance. A balance was thus struck between protecting utility IT systems and the privacy of customer data in a way that distributes the risks and responsibility amongst those entities electronically exchanging, receiving and/or collecting customer data with the utilities and facilitating the dissemination of customer information with customer consent to companies. Ultimately, a market where all parties observe cybersecurity and privacy protections would reduce the risks associated with electronic exchanges of customer data between distribution utilities and companies, instilling customer confidence and promoting market development.

NYSERDA Data Order

In its Order Regarding New York State Energy Research and Development Authority Data Access and Legacy Reporting, the Commission authorized utilities to transfer non-anonymized, non-participant customer data to NYSERDA and established a process for facilitating the data requests while ensuring appropriate protection of the datasets.[29] NYSERDA sought the data transfer to carry out its statutory duties relating to assessment of program and policy goals and the effectiveness of clean energy programs and policies, including potential, baseline, and market-characterization studies, as well as other Evaluation, Measurement, and Verification (EM&V) activities. To effectuate the flow of customer data between the utilities and NYSERDA, the Commission required NYSERDA and the Joint Utilities to develop and file a Memorandum of Understanding (MOU) for the request and transfer of customer data sets for the specifically approved purposes, including non-participant data.[30]

Joint Utility Cybersecurity and Data Privacy Risk Strategy – DSIP Appendix E

The DSIP Guidance Order required the utilities to jointly develop an evolving cybersecurity program that incorporated new technology and updated information regarding threats and countermeasures. Accompanying the JU Supplemental DSIP filing, was Appendix E: Cybersecurity & Privacy Strategy Framework (DSIP Appendix E). This document was reported to be a risk-based approach to

[29] Case 14-M-0094, et al., Order Regarding New York State Energy Research and Development Authority Data Access and Legacy Reporting (issued January 17, 2019).

[30] The Commission affirmed that NYSERDA's data governance protocols and non-disclosure agreements must ensure protection of non-participant datasets received from the utilities held by NYSERDA or its contractors and must ensure that the data requested not be used for the financial gain of any third party and should include appropriate remedies for any data breach. The process prescribed by Commission by which NYSERDA is to request data from a utility requires NYSERDA to: identify the need for data; identify specific data fields, as well as time period, and frequency of refreshing such data set; the planned retention and use of such data; and provide a justification for the need for data. The requested utility must respond with the data or identify why the utility believes the request is not consistent with the permissions provided in the NYSERDA Data Order, detailing the utility's objection to the data set request. Should a utility object to a requested data set, Staff shall review the NYSERDA request and the utility objection and make a determination in response to the objection, which may include approving the request, rejecting it, or approving it with modification.

cybersecurity and privacy that incorporated numerous industry standards,[31] while allowing the flexibility for individual utility implementation. This strategy was used as the utility starting point for adoption of a formal risk management program and the determination of the necessary cybersecurity and privacy requirements for entities seeking access to energy related data and, subsequently, the creation of the DSA.

The development of the individual utility cybersecurity risk management programs, and the determination of requirements, has led to varying implementation strategies. With the differences in utility IT systems the implementation strategies are, understandably, not wholly consistent. The Joint Utilities intended DSIP Appendix E to be flexible enough to account for IT system differences across utilities and allow for individual utility implementation strategies. However, DSIP Appendix E turned out to be overly broad and generic. For example, it lacks concrete guidelines for implementation processes and fails to provide definitions of key terms, which has resulted in significant differences in how utilities define data sets, group data, and assign risk-based requirements. Indeed, most of the ESE complaints focused on this lack of uniformity and ultimately led to the Joint Utilities, Staff, and the ESEs engaging in a collaborative, business-to-business process.

Before issuance of the Cybersecurity Order, the Joint Utilities developed cybersecurity and privacy requirements from the JU risk management program, which became part of the necessary requirements for ESE access to data. While the DSIP Appendix E is a risk-based model and the cybersecurity and privacy controls implemented from it are valid for risk mitigation, Staff believes that the requirements, as applied, do not adequately address the actual risk associated with various types of data access or the customer's choice regarding data sharing.

With the continued disagreement between ESEs and utilities over the reasonableness of cybersecurity and privacy requirements and who they apply to, the Commission adopted in the Cybersecurity Order a minimum level of cybersecurity and privacy protections which were subsequently implemented by the utilities. Since that time, some ESEs have informed Staff of inconsistencies regarding the applicability of these minimum protections across utilities. For example, upon its own review, Staff determined that there are disparities regarding how each utility interprets the Cybersecurity Order with respect to which ESEs are required to have cybersecurity and/or privacy requirements.

In summary, while the various data access rules and requirements are meant to provide the means to safely allow access to energy-related data, the ability of an ESE to gain access to data, and customers'

[31] NIST, NIST Interagency/Internal Reports (NISTIR), Fair Information Practice Principles, Electric Sector Cybersecurity Capability Maturity Model, Department of Energy DataGuard Energy Data Privacy Program, American Institute of Certified Public Accountants (AICPA) Generally Accepted Privacy Principles, International Organization for Standardization/International Electrotechnical Commission (ISO/IEC) standards, and Information Security Forum General Information Security Practices.

ability to share their data, continues to be limited. Based upon its analysis, Staff believes there are several reasons for the limited sharing of energy data, including a lack of standardized requirements and utility implementation strategies, as well as variability between utilities of the requirements for both customers and ESEs to get access to that data.

The ability to obtain useful access to useful data has been largely hampered by:

- Requirements developed in multiple proceedings, some of which are specific to market participants and others that are specific to the data access method, such as GBC. This has led to confusion regarding what requirements apply to whom.
- Difficulties with modifying existing requirements as data access standards evolve resulting in outdated and inconsistent requirements throughout different proceedings.
- Inconsistent interpretation of data access requirements which increases ESE confusion and extends the time necessary to be approved for data access.
- Inconsistent implementation of data access applications or tools across all utilities.
- Inaccurate and/or incomplete data, as well as extended delays in receiving data.
- Lack of customer awareness of their rights to control their data.

3. The Key to Unlocking Useful Access to Useful Data

In order to unlock access to energy-related data in New York, a statewide Data Access Framework must be adopted that incorporates the work from existing data access policies, defines the necessary process and requirements for access to energy-related data, introduces requirements for data quality and integrity to facilitate consistent application throughout the State, and enables access while still providing appropriate protections. The proposed Data Access Framework would provide clear and consistent rules and related implementation, define roles and responsibilities, create confidence in the quality of the data, and ensure that the appropriate entity is accessing data in a secure manner. The proposed Data Access Framework would also address the existing requirements related to customer consent and associated improvements upon them.

Adopting the proposed Data Access Framework would create a single source for data access policies and requirements and provide uniform and consistent guidance on what is needed for access to, and the availability of, energy-related data to better support the purposes of existing data policies, while ensuring the appropriate protections are in place. The proposed Data Access Framework provides clear paths that address the roadblocks described above and establishes the necessary foundation to address any new issues that may arise as markets evolve.

To meet these goals, the Data Access Framework would:

- establish a universal approach for any ESE seeking access to energy-related data that would apply statewide, regardless of utility territory, thus removing the need for utilities to spend time and money on individual ESE risk management processes and oversight;

- provide a clear and consistent ESE data access approval process that better supports the purposes of existing data policies by implementing an ESE risk management model with a Data Ready Certification;
- define key terms, key applicability considerations, and requirements for access;
- incorporate all the separate existing data requirements from the Commission and the utilities into one clear set of requirements that appropriately recognizes risk;
- centralize all existing access requirements and ensure that appropriate cybersecurity and privacy protections are in place to protect IT systems and the data they house; and,
- recognize customers' right to consent to share their energy usage data and encourage customer control of their energy-related data.

The proposed Data Access Framework endorses a risk-based approach to managing cybersecurity and privacy risks associated with allowing access to energy-related data. Adoption of a risk-based approach would provide a standardized process, along with defined requirements, for access to energy-related data, while still ensuring the necessary protections are in place. The Data Access Framework also recognizes customers' right to access and share their useful data and enables useful access to energy-related data by ESEs. The Data Access Framework provides an identification of rules, roles, and responsibilities for parties seeking access to energy-related data and ensures uniform treatment of energy data access requests, regardless of where the data are being housed, which provides certainty to customers, utilities, and ESEs. This Data Access Framework, if adopted by the Commission, would become the guiding document for determining the necessary requirements and process for access to energy-related data going forward.

ESE Risk Management and Data Ready Certification

The proposed Data Access Framework would implement an ESE risk management model, as well as creation of a Data Ready Certification program, managed by an outside party. The Data Ready Certification would require an ESE applying for certification to complete DPS registration requirements, detail access consideration information (purpose, transmittal mechanism, and data sets), and have cybersecurity and privacy requirements verified. Under this approach, once an ESE is certified as Data Ready, the ESE would be in position to request access to data from any data custodian, without having to go through each individual data custodian verification requirements because the data custodian would be able to easily confirm the data to which the ESE has been certified for access, and the means by which the data may be accessed.

Taking these actions would resolve the inconsistent implementation issues identified above, remove the need of ESEs to go through duplicative processes with each utility, significantly speed up the ESE verification process, enable access to data while providing assurance that the ESE has the necessary protections in place, and provide a consistent understanding and implementation of a data access program. This standardized ESE approval process would ensure that, before being approved to access energy-related data, all ESEs have completed the necessary onboarding requirements and have the appropriate cybersecurity and privacy protections in place.

Currently, when a customer wants to share his or her energy usage data with an ESE, the process, and ease in doing so, varies significantly by utility. The ESE with whom the customer consented to share that data must work through onboarding requirements that have been implemented inconsistently amongst the utilities as well as unclear policies and requirements if they want to get access to that data, and possibly provide a benefit to that customer. Commission actions meant to promote customers' right to share their data and enable market offerings, such as GBC, have not been successful to this point because of these ongoing problems. Instead of the utilities evaluating the necessary requirements and the ESE's readiness to access data, an ESE risk management program, as Staff proposes, would ensure that the appropriate risk mitigation controls are in place to protect IT systems and the data they house, and that the requirements are applied in a consistent manner, regardless of the utility.

As illustrated below, the current process may include multiple steps for any ESE seeking access to energy-related data, which has contributed to the limited availability and sharing of energy-related data. The proposed process reduces the number of steps, provides a consistent and uniform treatment of all parties, while still ensuring the necessary cybersecurity and privacy requirements have been met to protect IT systems and the data they house. The Data Ready Certification approval process detailed below would utilize the existing cybersecurity and privacy protections and streamline the approval process while still ensuring those protections are in place. In other words, while Staff proposes a new certification process for data access, the required cybersecurity and privacy protections are not new. This certification would also implement data relationship requirements that provide necessary data quality and integrity standards.

Current ESE Access Process

1) ESE registers with DPS and completes all requirements under applicable UBP (including privacy and cybersecurity).
2) ESE contacts utility to request access to data.
3) ESE must sign a DSA with utility and provide. Verification.
4) ESE must go through onboarding and connectivity testing with utility.
5) ESE must meet any other utility specific obligations.
6) ESE requests data from utility.
7) ESE receives data from utility.
8) ESE must review the data for consistency and verify integrity.
9) ESE works with utility to correct any data issues.
10) ESE must repeat this process for EACH UTILITY from which it seeks to access data.

Proposed Data Ready Certification Process

1) ESE registers for access:
   a) Provider verifies applicant is an authorized ESE.
   b) ESE details purpose, transmittal/access mechanism, and data type.
   c) Necessary ESE cybersecurity and privacy protections, based upon registration information, are validated.

ESE is assigned an Access Role that dictates the data they are approved to access and how they can access it.

2) ESE requests data from data custodian (utility, centralized data warehouse, etc.).
3) Data custodian verifies ESE Access Role.
4) ESE receives data from data custodian that is uniform and correct.

While it is a significant change to the current approval process for an ESE seeking access to energy-related data in New York, an ESE risk management program is not a new concept or model. The United Kingdom (UK) implemented its Cyber Essentials Scheme on October 1, 2014 and made it a mandatory requirement for any entity wanting to bid on any central government contract and, going a step further to try to ensure data protections, the UK recommended its use by private sector organizations.[32] The Cyber Essentials Scheme established a centralized certification process that requires verification of specific cybersecurity and/or privacy requirements which are based upon the information (data) that would be shared. The registration process, verification of requirements, and subsequent certification is done by an outside company, IASME Consortium,[33] that provides a web site listing of certified entities, what data they are permitted to access, and by what means. This listing is then used by governmental procurement personnel for verification that an entity has met the required standards to allow sharing of the data with the entity, all without having to perform audits or monitoring on their own.

As another example, beginning in July 2015, Fannie Mae rolled out a similar certification model, managed by BitSight, that provides a portal with a centralized listing of all the registered and tested third parties.[34] The third parties are assigned a security score and a rating of basic, intermediate, or

[32] Available at: https://www.ncsc.gov.uk/cyberessentials/overview.

[33] Available at: https://iasme.co.uk/cyber-essentials/.

[34] Available at: https://info.bitsight.com/sans-whatworks-case-study-fannie-mae.

advanced, based upon the cybersecurity and privacy requirements the third party has in place. Currently, BitSight is providing third-party vendor risk management services to over 1,700 businesses and reportedly can complete vendor assessments in hours, instead of the weeks it would normally take a business to do it on its own.[35]

The need to ensure the appropriate cybersecurity and privacy protections are in place cannot be understated, but the need to determine the most efficient and expedient means to do so is equally important. Centralizing the requirements, as well as the verification of completion of those requirements, would allow for an efficient and consistent process for ESEs to request, and access, energy-related data. Doing so is intended to both ensure that the appropriate protections are in place and reduce the frustration of ESEs and customers seeking data access. Additionally, by establishing a single process, Staff proposes to reduce the time and cost for utilities associated with the current ESE approval processes that are outside the traditional utility business model. This Data Ready certification process would determine the applicability of existing requirements based upon the ESE's purpose for requesting data access, the transmittal or access mechanism utilized, and the data being requested.

Incorporating all existing data access requirements into one Data Access Framework would eliminate inconsistent implementation and application of data access policies and allow for a true dynamic document that upon modification, applies to all entities seeking access to data. This would address current inconsistency issues with the UBPs as well as the CCA DSA.

The CCA DSA was implemented prior to the Cybersecurity Order, as such, it is no longer wholly consistent with the current standards of what is necessary for data access. While work has begun to modify the CCA DSA to ensure its consistency, a mechanism for expedient changes does not currently exist. Under the proposed Data Access Framework any changes going forward would be applied uniformly to all markets and ESEs, at the time of the change, eliminating these types of problems.

The UBPs, while similar, do have differences in the requirements for obtaining access to customer information, and this inconsistency does not provide for a consistent and uniform level of protection. The DER UBP requires: "DER suppliers that obtain customer information from the distribution utility or DSP must have processes and procedures in place regarding cybersecurity consistent with the National Institute of Standards and Technology Cybersecurity Framework" and "DER suppliers that obtain

[35] Available at: https://www.bitsight.com/security-ratings-vendor-risk-management.

customer information from the distribution utility or DSP must comply with any data security requirements imposed by that utility or by Commission rules on ESCOs and/or any data security requirements associated with EDI eligibility."[36] The ESCO UBP, on the other hand, does not define any necessary cybersecurity requirements, or measures, pertaining to obtaining customer information.[37]

Due to a lack of uniformity in what each utility provides, including how it is provided, Staff has received numerous complaints regarding ESEs first having to standardize the data it received before it can be used. This causes an additional burden upon ESEs seeking access to data by now requiring them to take additional steps in order to make the data useful. Platforms to which the utilities provide data, such as the UER and GBC, have also seen inconsistent data standards and output. As previously discussed, GBC implementation was seen as a way to address these concerns by providing a standardized and uniform means for the sharing of data, but due to inconsistent implementation of GBC, these problems still persist. By establishing data quality and integrity standards, as well as enforcement mechanisms, the significant number of problems related to the inconsistency and quality of the data being provided would be resolved.

The recommendation to create a Data Access Framework Application Guide provides an additional mechanism to ensure clear understanding of what the ESE needs to do to be approved for access, the responsibilities of each party, the dispute resolution process, and defines key terms that will be used throughout all energy-related data proceedings. Customers further benefit by having a known and written set of policies and practices that would be employed by utilities and any ESEs that are authorized to obtain customer data. This includes obtaining a notice from utilities and ESEs when data is requested, a contact person at the utility to ask questions, the ability to obtain his or her own information, and the opportunity to dispute and request changes to his or her information.

4. Proposed Data Access Framework

4.1. Purpose

The purpose of this proposed Data Access Framework is to enable access to, and appropriate use of, energy-related data that enhances customer data protections, furthers the trust relationship between ESEs and consumers, and enables innovation while also avoiding regulatory fragmentation that undermines New York State goals.

[36] UBP DERS, Section 2C(F), (G), p. 10.

[37] UPB ESCO, Section 4.

4.2. Applicability

The proposed Data Access Framework applies to any entity seeking access to energy-related data, regardless of where the data are housed. By the condition of seeking access to energy-related data from the data custodian, ESEs would need to agree to abide by the terms of this proposed Data Access Framework. The Data Access Framework is not intended to modify the way that individual utility customers currently access their specific account data and, as such, does not seek to change, or in any way inhibit, an individual customer's right and ability to access his or her own data.

4.3. Enforcement

If an ESE is not complying with the requirements for data access, there are existing enforcement mechanisms available, such as those in the UBPs, which are tied into the ESE's ability to be an eligible New York State energy service provider. Staff recommends the proposed Data Access Framework incorporate the existing enforcement standards, where possible, to provide one concise enforcement process. Depending on at what point the ESE is non-compliant may determine what the appropriate enforcement mechanism may be. For example, if an ESE is not meeting the necessary requirements for Data Ready Certification, they will not be certified and will not be able to access data. If they are certified but are not complying with DPS requirements, the combined enforcement mechanism would be used to suspend an ESE's Data Ready Certification.

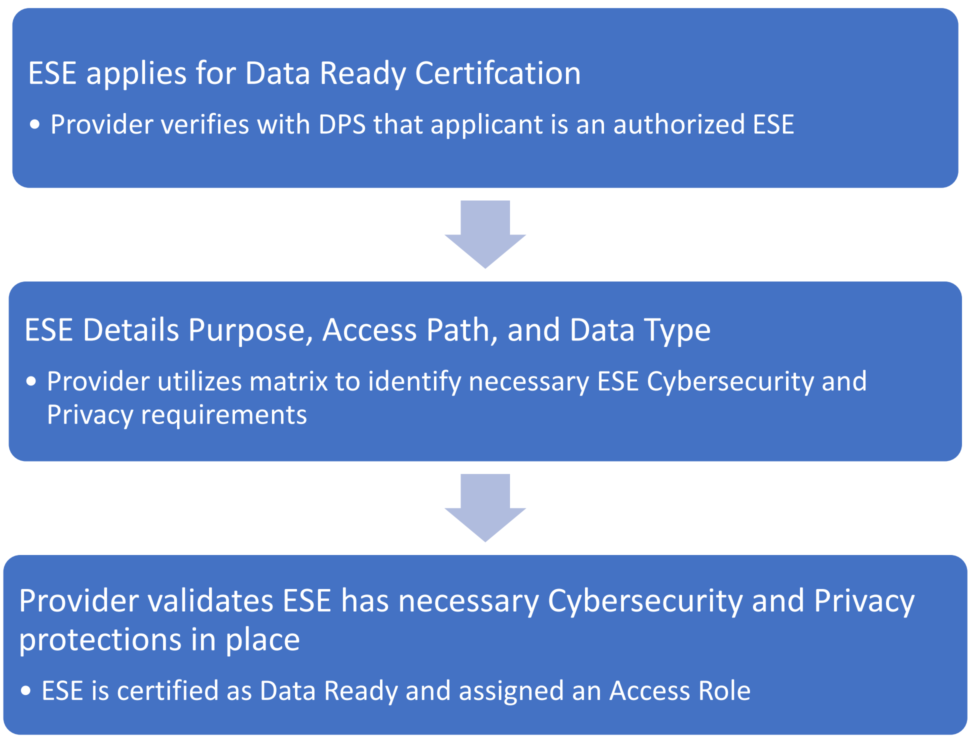
4.4. ESE Data Ready Certification Process

Staff recognizes that there have been challenges for ESEs seeking access to energy-related data. Seeking to address those challenges, Staff proposes an access request process that incorporates all the existing, separate requirements from the Commission and the utilities into one process, and establishes a universal approach for any ESE seeking access to energy-related data that would apply statewide, regardless of utility territory. This process would require verifying that the appropriate cybersecurity and privacy protections are in place, and thus the proposal includes the creation of a Data Ready Certification program. Any entity seeking access to energy-related data, would need to follow the access request process and meet all requirements before being approved and assigned an access role.

Staff recommends implementation of an ESE risk management program that provides a Data Ready Certification. The program is to be managed by a risk management solution provider (Provider) who would build the Data Ready Certification model based upon this proposal. The Provider would utilize a matrix that defines the existing cybersecurity and privacy requirements based upon the ESE access considerations below. The Data Ready Certification would require confirmation/testing that ESE cybersecurity and privacy requirements are in place, which may be done directly with the Provider or as an audit. When an ESE applies for Data Ready Certification, the Provider would only be responsible for confirming all the requirements have been met and would not be determining what those requirements are. The necessary cybersecurity and privacy requirements would be included in the matrix, which will compile all existing requirements, as discussed below. In addition to the verification of the existing requirements, Staff recommends a requirement for annual re-certification. This would ensure that ESEs are remaining current with the necessary protections. Failure to complete the annual re-certification would result in the ESE losing its certification and, consequently, its ability to access energy-related data.

Once an ESE has completed the requirements for approval, the ESE would be certified as Data Ready. That certification provides the assigned access role which dictates what types of data it may request to access, and how they are able to access it. This certification would apply no matter from which utility, or data custodian, the ESE is seeking to access data. There would no longer be a need for utilities to oversee or confirm the appropriate protections are in place, saving them a significant amount of time and resources that have been dedicated to this type of oversight role.

<u>Data Ready Certification Process</u>

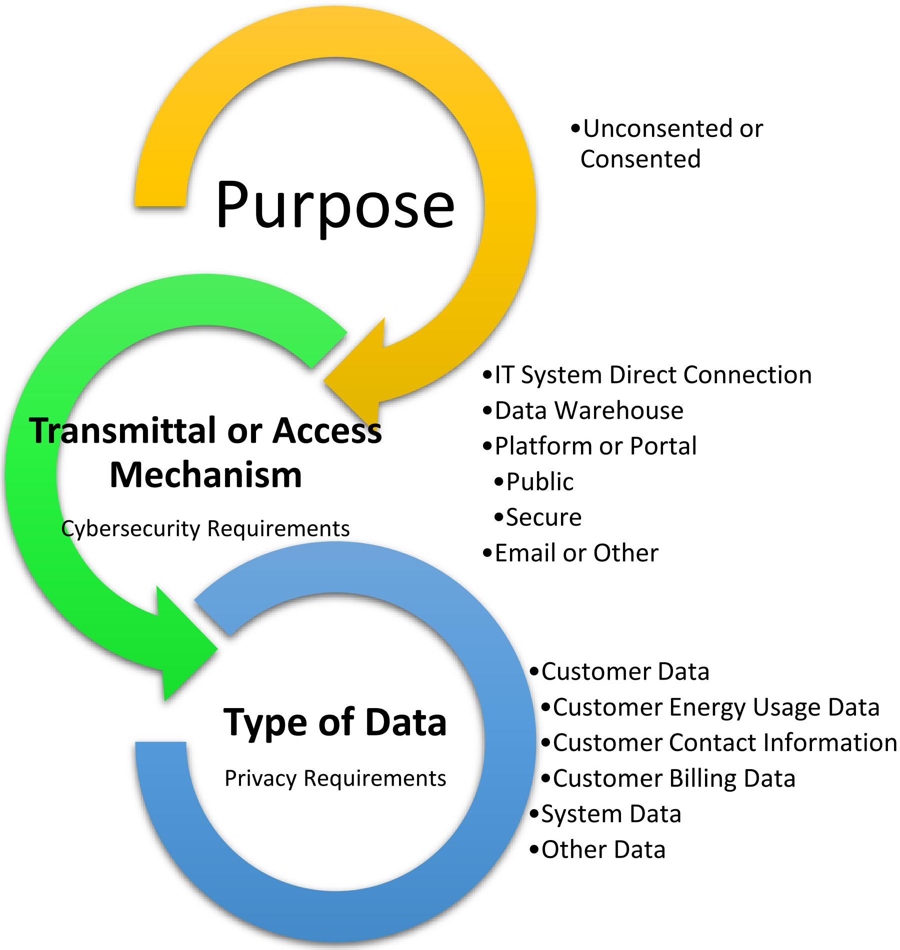


4.4.1. Authorized ESE Verification

Upon receiving an ESE certification request, the Provider would first verify that the applicant is an authorized ESE. The applying ESE will have to have completed all necessary DPS requirements before the ESE will be approved as an authorized ESE. To ensure that any ESE that is seeking access to energy-related data has been properly authorized by DPS, Staff proposes to develop an authorization mechanism for any ESE that is not currently subject to registration or authorization requirements through existing Commission Orders. Currently, there is not a centralized listing that provides the information for all approved ESEs. However, there are market-specific listings available. Staff proposes to evaluate the creation of such a listing or other means by which the Provider could verify the applying ESE has been authorized to provide service(s) to utility customers.

4.4.2. Access Considerations

The necessary cybersecurity and privacy requirements for access to energy-related data should be determined by the following access considerations: the purpose for accessing the data, the mechanism by which the data are being accessed or transmitted, and the data type for which access is being requested.



As can be seen above, the second step in the approval request requires an ESE to provide the details of the purpose of accessing the data, how they will be accessing the data, and the type of data they are requesting. The necessary cybersecurity protections would be determined based upon the access or transmittal mechanism and the privacy protections would be determined based upon the data type being accessed. In some instances, there may be privacy requirements but not cybersecurity requirements, or vice versa.

4.4.2.1. Access Considerations: Purpose

When requesting access to energy-related data, an ESE would first detail for what purpose the data are being sought and whether the ESE has obtained customer consent. Upon determining the ESE request is valid, the Provider would use this information to determine the data sets available, as well as the granularity of such data, by using the matrix.

Valid purposes for requesting access to unconsented energy-related data include: (1) providing or reliably maintaining customer-initiated service; (2) including compatible uses in features and services to the customer that do not materially change reasonable expectations of customer control and ESE data sharing; or (3) disclosure pursuant to Commission Order and/or State, Federal and Local Laws or regulations. Examples of these actions include, among other things, issuing a bill for energy consumption, implementing a demand response program, implementing an Energy Efficiency (EE) program or other Commission authorized program like CCA, or to meet utility operational needs.

Unconsented data would be anonymized or aggregated before access is granted, with exception for data used for utility operational need or data required to be available, pursuant to Commission Order and/or State, Federal and Local Laws or regulations. In the event customer consent is received after receiving unconsented data, the ESE purpose, and requirements, would then change to be consistent with customer consent and the customer's choice.

Aggregated Data

Aggregated Data are a combination of data elements from multiple accounts to create a data set that is sufficiently anonymized as to not allow for the identification of an individual account or customer. As previously discussed, the Commission has adopted different privacy screen standards for different use cases such as community wide planning, CCA, UER reporting, and building benchmarking.

Anonymized Data

Anonymized Data are data sets containing individual sets of information where all identifiable characteristics and information including, but not limited to, name, address, or account number, are removed (or scrubbed) so that one cannot reasonably re-identify any individual customer within the data set.

4.4.2.2. Access Considerations: Transmittal or Access Mechanism

When considering what cybersecurity protections need to be in place for access to energy-related data, it is necessary to evaluate the means in which that data will be transmitted or accessed. There are varying degrees of risk, all dependent on the mechanism used for accessing or transmitting the data. In many cases, current utility processes do not recognize these differences and instead, assign the same level of risk regardless of how the data are being accessed. Cybersecurity protections are controls that are put in place to address the risk to IT systems and the data they house. The electronic transmittal or access to data can be done through a direct connection between IT systems or through a system platform or portal.

Direct Connection to Data Custodian IT System

Having a direct electronic connection to the IT system of a data custodian, such as the utility or a data warehouse, increases the risk to those systems and, as a result, the data they house. Though the data custodian should have proper risk mitigation controls implemented, the ESE connecting directly into the system (not through a data sharing portal, such as GBC) must have the appropriate cybersecurity protections to limit the risk from their side as well. In many instances, though a direct connection should be limited in what it is able to access, it is a connection that may come in behind the customer information system firewall, which increases the risk associated with access. Properly implemented system controls require separation of information to reduce the risk, but the risk of a breach remains. These direct connections are most often done by EDI or Application Programming Interface (API) transfer protocols and are typically associated with customer enrollment and the billing of a customer account. In most instances, this type of connection will require the highest level of cybersecurity requirements.

Centralized Data Warehouse

A centralized data warehouse is an alternative location for all energy-related data to be stored and accessed from. While New York does not currently have this resource available, the development of such a resource is being evaluated and will be discussed in a companion Staff whitepaper in this proceeding. If an ESE is seeking access to energy-related data from a centralized data warehouse, the requirements would be based on how the data will be accessed – through a direct connection or through a platform or portal.

Secondary Access: Platform or Portal

Secondary access may be through a public-facing or secure platform or portal, and the requirements will vary for each. Electronically accessing data through a secondary access point may require the ESE have cybersecurity protections in place. However, what the cybersecurity requirements are can vary depending upon the protections built into the platform as well as whether the data are publicly available. The primary difference between secondary access and direct connection access is where exactly the ESE's IT system is connecting to the data custodian's IT system. When obtaining data through a secondary access point, though it may back trace into the data custodian's IT system, it is not a direct connection – meaning the platform or portal sits in-between the data custodian IT system and the ESE IT system. Properly implemented cybersecurity plans would require controls by the data custodian on the backend of that connection to limit the possibility of unauthorized access. Additionally, consideration should be given to cybersecurity controls that may already be part of the platform and to whether the data being provided are publicly available. Staff notes that there are existing public portals that provide system data and aggregated data, many of which do not require cybersecurity or privacy protections.

Public Platform

Those seeking access to energy-related data from a public platform are able to do so without needing to meet any Commission or utility requirements. Publicly available data are inherently protected, when necessary, before being made available to the public through anonymization and aggregation standards. As an example, the UER provides aggregated community level usage information but does not require ESE registration or any cybersecurity and privacy protections to access it. Public platform use should not require any certification.

Secure Portal or Platform

The other type of secondary access may be through a secure portal or platform, such as GBC. These access points, when properly implemented, reside separate from the servers that house any highly confidential personal information. A secure platform may represent a lower risk due to that separation and because many of these secure access points have been designed with cybersecurity and privacy controls built in. For example, when properly implemented, GBC includes requirements for, among other things, data transmittal that separates the data streams. This type of integrated control could meet the requirement that would otherwise need to be implemented by the ESE. Each secure platform or portal would be evaluated to determine if there are built-in protections and, if so, if they meet the requirements that are necessary to protect the IT systems and the data they house.

4.4.2.3. Access Considerations: Data Type Requested

The data type to which an ESE is requesting access would determine what the necessary privacy requirements should be. Data are initially considered in two separate categories, customer data and system data. In addition to the evaluation of the risk associated with the data type being requested, customers' right to choose to share their data must also be recognized and considered.

With the intention to empower customers and enable access to data in a uniform and consistent manner, Staff recommends adoption of the specific data sets defined below when determining the necessary privacy requirements for ESE access to energy-related data. In considering what data should be included in what sets, Staff looked to the CCA Framework Order as a successful example of energy-related data sets that have been used for controlled access to energy-related data. The CCA Framework Order data sets were developed in a way that allows for release of specific data sets for different purposes during the implementation of an opt-out CCA program. The available data were defined in three separate categories: (a) aggregated customer and consumption (usage) data to support procurement; (b) customer contact information used to send opt-out letters; and, (c) detailed customer information for the purpose of enrolling and serving each customer.[38] Whilst there are many data components included in these three categories, no data are available other than what is necessary to facilitate the ESE program. In other words, no highly confidential personal information, such as social security number or banking information, is available or included under these defined categories.

The utilities IT systems record, and house, a significant amount of data, much of which is outside what is needed by ESEs. Staff recommends that highly confidential personal information, such as social security number or banking information, not be made available or shared for any purpose. Adopting a similar model to what was implemented for CCA programs would best enable useful access to useful data, while still providing strong privacy protections by limiting what data is made available. Any customer data sets not included in a data category below would not be available for sharing. However, as needs change, each data set and the data they include, could be addressed through the continuous improvement process discussed below in Section 4.8.

Customer Data Sets

Eligible customer data are separated in three different data sets, each of which has a different level of risk associated with allowing access to that data. The necessary requirements to protect that data would be assigned based upon that risk. However, these requirements may be modified upon customer consent for release of his or her data. A customer's right to share his or her energy-related data should be recognized and is a necessary consideration in determining the necessary ESE protections of that data. These details are discussed later in a separate section on customer consent.

Customer Contact Information Data Set

This data set contains information that is specific to the individual and should only be available for ESEs that are requesting access for a valid purpose including: (1) providing or reliably maintaining customer-initiated service; (2) including compatible uses in features and services to the customer that do not materially change reasonable expectations of customer control and ESE data sharing; or (3) providing pursuant to Commission Order and/or State, Federal and Local Laws or regulations, or upon customer consent. The following data elements are to be considered part of the Customer Contact Information Data Set: customer of record's name(s); service address; mailing address; phone number; and primary language, if available, as well as any customer-specific alternate billing name, address, and phone

[38] CCA Framework Order, p. 43.

number. The separation of this data set provides the necessary details to facilitate the request for customer consent while protecting customer privacy and recognizing a customer's choice to share his or her data.

Customer Billing Data Set

The Customer Billing Data Set includes the necessary account information to facilitate enrollment and billing of the customer's account. There are existing requirements for what data must be included for billing and enrollment of accounts through, for example, the UBPs. These required data components can be combined under one Customer Billing Data Set that provides the necessary information regardless of market.

The Customer Billing Data set is a master listing of the available data and includes components that may be part of other data sets or only applicable for an electric or gas account. This data set includes:

- Customer's service address, and billing address, if different;
- Account number;
- Electric and/or gas account indicator;
- Meter reading date or cycle and reporting period;
- Billing date or cycle and billing period;
- Customer's number of meters and meter numbers;
- Rate service class and subclass or rider by account and by meter, where applicable;
- Description of usage measurement type and reporting period;
- Budget billing indicator;
- Electric and load profile reference category or code, if not based on service class, whether the customer's account is settled with the New York Independent System Operator utilizing an 'hourly' or a 'class shape' methodology, or Installed Capacity (ICAP) tag, which indicates the customer's peak electricity demand;
- Life support equipment indicator;
- Gas pool indicator, for gas accounts only;
- Gas capacity/assignment obligation code;
- Customer's location based marginal pricing zone, for electric accounts only;
- Sales tax district used by the distribution utility and whether the utility identifies the customer as tax-exempt;
- Whether the customer receives any special delivery or commodity "first through the meter" incentives, or incentives from NYPA;
- The customer's Standard Industrial Classification (SIC) code;
- Usage type (e.g., kWh), reporting period, and type of consumption (actual, estimated, or billed);
- Whether the customer's commodity service is currently provided by the utility;
- 12 months, or the life of the account, whichever is less, of customer data and, upon separate request, an additional 12 months, or the life of the account, whichever is less, of customer data, and, where applicable, demand information. If the customer has more than one meter

associated with an account, the distribution utility or DSP shall provide the applicable information, if available, for each meter;

- Electronic interval data in summary form (billing determinants aggregated in the rating periods undera distribution utility's tariffs), and if requested in detail, an acceptable alternative format;
- Date of gas profile; and,
- Weather normalization forecast of the customer's gas consumption for the most recent 12 months or life of the account, whichever is less, and the factors used to develop the forecast.

Customer Energy Usage Data (CEUD) Set

CEUD is the data generated by a meter, for example, that describes a customer's usage. This data can be in kilowatts, kilowatt-hours (kWh), or any other data that the meter collects, such as voltage or current. This information can also include the rate a customer is on, and other billing determinants, such as bill cycle. In and of itself, the simple kWh amount will not provide much information about the customer. However, the CEUD becomes more valuable when paired with other data about a customer. CEUD can inform an ESE on potential energy efficiency investments that may be worthwhile, or whether a customer may be better off on a different rate design, or to generate the amount of compensation for any demand response product. CEUD reflects an individual customer's measured energy usage but does not identify the customer on its own.

With the rise of AMI, CEUD has become more valuable. Whereas before, with monthly meter reads, that information provided some high-level details about a customer, with AMI, which can collect data in 15-minute increments, much more granular information about customer behavior can be identified. For example, if a customer is not home during a peak hour time period, then perhaps the customer would be better off on a different rate based on his or her load profile. As discussed below there are several types of CEUD.

<u>Historical Data</u>

Historical data are the most recent Customer Energy Usage Data, preferably while at the same address and for at least 12 months. Historical data are used to analyze impacts of a particular technology or program and extrapolate that into the future. Historical data can be used to analyze impacts of a particular technology or program and extrapolate that into the future. It is important to have a full 12 months of data in order to account for any seasonal changes in a customer's usage. Historical data can be provided at one time since historical data are used for a baseline measurement or to run an analysis of usage. Historical data can also be at a specific granularity, if available. For example, an authorized ESE could ask for 12 months of 15-minute data, 12 months of hourly data, or 12 months of monthly data depending on the need for such data, and as authorized by the customer.

Real Time Data

AMI often collects data at a higher rate than what is provided back to the utility. While AMI collects data in 15-minute increments, for example, and sends that information to the utility every 6-8 hours, it is also possible for the customer to obtain data much more frequently. Typically, AMI contains a second radio to support the Home Area Network (HAN) access. For customers that have technology to communicate with the meter over the HAN, it may be possible to receive data every 8 seconds. In order to set up the process for the HAN, additional steps need to be taken by the utility to ensure the data are going to an authorized device. This may include a process for a customer to provide the utility with the Media Access Control (MAC) address of the device and be part of commissioning the device with the meter. To address cybersecurity risks of the HAN, it is possible to architecturally minimize the risks by implementing the standard in a way that does not allow two-way communication between the device and the meter or disables other functions of the communication standard.

Other Types of AMI Data

It is important to note that there are other data that can also be made available. For example, advanced meters collect more than just usage. These meters may also monitor current, frequency, voltage, and var, all of which are capable of being provided to customers via the HAN or collected by the utility over AMI networks. These data can provide customers or other third parties with more information about the impacts that other devices, technology, or usage patterns may have on their own usage, or as it impacts the grid. Existing standards may already contain fields allowing for that information to be shared. For example, GBC is currently capable of sharing these data sets if the data are capable of being shared. While not the immediate focus of this whitepaper, recognizing that there is additional information that is capable of being collected and shared with a customer or its authorized ESE shows the importance of a pathway for data access and the need for a data access Data Access Framework to ensure that these use cases and opportunities are not ignored.

System Data

System data are information about components and activity at the distribution system level. Most system data do not allow for identification of individual customers. However, there may be some system data that, while not CEUD, may still identify an individual customer. In those limited circumstances, system data can be aggregated with other local circuits to create an aggregated set of data that sufficiently reduces the risk of reidentification.

System data also include maps identifying the hosting capacity of circuits and the types of distribution circuits across a service territory. These maps can provide the market with important information about the potential ability of a resource to successfully interconnect at a location. Information about the operation of the electric system is generated by devices located across the system. This information includes performance of the distribution system collected from distribution transformers, distribution substations, and information to generate hosting capacity analysis. The accessibility of system data is imperative for creating the benefits as envisioned under REV and in support of the State reaching its clean energy goals. For example, development of non-wires alternatives requires more data about the system in order to target solutions and technologies to meet a non-wires alternative request. Developers need better insight into the hosting capacity of the distribution system in order to better understand locations across the grid with a higher likelihood of success in the interconnection process. Alternatively, the same data can be used by demand response, energy efficiency, or energy storage developers as possible locations to alleviate a constraint or congestion, i.e., areas where the value of distributed energy resources may be higher.

For system data, except for those pieces of system data that may impact customer privacy or critical infrastructure protection, there should be no protections on the availability of such data, since it is aggregated data itself. Since it is not CEUD, it is not subject to customer consent. System data should also be made available to the public. Some of the utility's hosting capacity maps are public, while others require user registration with the utility. Users should not be required to register with the utility prior to access.

4.4.3. Determination of Risk-Based Cybersecurity and Privacy Requirements

After the ESE has provided the necessary access consideration details, the Provider would determine what existing cybersecurity and privacy requirements would apply. The necessary cybersecurity and privacy requirements applicable to the combination of ESE purpose, access mechanism, and data type would be determined by applying existing Commission requirements. Though there are multiple Commission documents that reference data access requirements, the primary documents pertaining to requirements for an ESE to access energy-related data, and that detail the responsibilities of the ESE to the customer and to the utility, are the ESCO and DER UBPs, and the cybersecurity and privacy requirements adopted by the Commission in its Cybersecurity Order. To facilitate this process, Staff proposes the development of a matrix that maps the existing cybersecurity and privacy requirements to the various combinations of purpose, access mechanism, and data type that can result from application of the Data Access Framework. This matrix would then be used by the ESE risk management Provider to determine what cybersecurity and privacy requirements and ESE would need to demonstrate compliance with to be certified.

When enabling access to energy-related data, it is necessary to consider the risk to IT systems and the risk to the privacy of the data they house. The primary goal of instituting privacy and cybersecurity protections is to reduce that risk but in order to do so, we must first understand what is at risk, and how significant that risk is. Risk management is an essential component of the Data Access Framework and ensures that any risk to confidentiality, integrity, and availability is identified, analyzed, and maintained at acceptable levels. Implementing a risk-based Data Access Framework is consistent with Commission-authorized requirements, current utility implementation strategies, and industry actions.

The proposed Data Access Framework incorporates requirements that have been determined through implementation of risk management frameworks and models. There are a multitude of possible cybersecurity and/or privacy controls that can be implemented as a way to mitigate the risks associated with data access, for example:

- Allowing CEUD to be made available, but not highly confidential personal information, is a risk-based approach.
- Recognizing that aggregated and anonymized data have different levels of risk and, when appropriately compiled, have less risk of re-identification, balances privacy risks with societal benefits.
- Adopting a statewide Data Access Framework and single process reduces risk by ensuring that uniform standards are being adhered to across the State.

The ESCO UBP and DER UBP (UBPs)

The UBPs detail the necessary requirements for an ESCO or DER to provide service to New York consumers and define the obligations between the utility and the ESE pertaining to, among other things, the data-sharing timeframes and data sets transmitted. The UBPs include the Department's registration process for their respective industries. The UBPs include similar, and in some areas identical, requirements for the transactions between the ESE and customer. It is important to note that the UBPs do include areas that would be outside of what is proposed to be incorporated into the matrix, such as Marketing Standards, EDI Requirements, Registration and Eligibility Requirements, Billing and Payment Processing, and Creditworthiness standards. This proposal does not include any recommendations pertaining to the processes and requirements associated with eligibility, registration, or compliance that have been established in the UBPs. The UBPs define necessary requirements for the interactions with customers. These requirements are controls meant to ensure customer consent is obtained, protect customer privacy, and ensure that customers receive notice of changes to their service. These requirements are generally, but not completely, consistent between the two documents.

The Cybersecurity Order

The Cybersecurity Order provides defined cybersecurity and privacy requirements that are meant to serve as risk mitigation controls. These controls overlap in some areas within the Order, as well as with the requirements of the UBPs and other Commission proceedings. There are two aspects of the privacy controls required – those that specifically define the requirements of the ESE with their interactions with the customer, and those ESE requirements to implement controls that minimize data privacy risk generally. The privacy requirements also define what can be done with the data and how it is categorized. Cybersecurity requirements include, but are not limited to, actions needed at all levels of the ESE and include policies, as well as data handling requirements.

The proposed Data Access Framework should also recognize that existing state, federal and/or local legislation will need to be considered when making data access decisions. For example, the State's Stop Hacks and Improve Electronic Data Security (Shield) Act broadens the scope of consumer privacy and places requirements on protecting personal data for organizations that collect information on New York residents.[39] Additionally, utilities must remain in compliance with their respective Critical Infrastructure Cybersecurity Plans which may restrict access to certain data components.

4.4.4. Verification of Requirements and Certification

Verification that the ESE has the necessary cybersecurity and privacy requirements is the last step for an ESE to become certified as Data Ready and assigned an Access Role that identifies the types of data they may request to access, as well as identifying the transmittal mechanisms they are able to utilize. The access role is based upon the access considerations and the verification of meeting the necessary requirements.

4.5. Certified ESE Data Request

Once an ESE has received its Data Ready Certification, the ESE would be able to request access to data defined under its assigned Access Role. The Access Role provides the data sets and access mechanisms for which the ESE has been certified to have the appropriate cybersecurity and privacy requirements in place.

As an example, an ESE requests EDI direct IT system connection for Customer Billing Data set. The Data Custodian confirms the ESE is Data Ready and that its Access Role allows for that data set to be transmitted through a direct connection, either through a manual or automated review of Data Ready Certified ESE listing. Once confirmed, the Data Custodian allows the data to be accessed.

4.6. Utility Connection Requirements

While the ESE Data Ready Certification program would provide a centralized process for seeking access to energy-related data, it would not address the requirements for utility connectivity testing. If an ESE is seeking direct connection into the utility IT systems, whether by EDI, API, or other means, the ESE would still need to complete the required testing and connectivity requirements. These requirements should only be for direct system-to-system connection and should not include requirements outside of testing that connection. This system-to-system connectivity testing may also apply when the data custodian is not the utility, such as with a data warehouse direct connection.

[39] Chapter 117 of the Laws of 2019.

4.7. Data Responsibilities and Relationships

While there are defined responsibilities for an ESE interaction with the utility, and the customer, the responsibilities of the utilities to the ESEs seeking access to data have yet to be established in a way that promotes meaningful data quality standards. The Commission acknowledged this in its Cybersecurity Order, stating "notably absent from the DSA are the obligations of the utility for service levels and processes when they are providing data to ESEs."[40] The need for such standards is supported by market participant feedback where, in multiple proceedings, requests have been made for development of utility-side requirements and responsibilities to the ESEs for data access. Staff has worked with parties trying to resolve issues with, among other things, data time frames, onboarding problems, data quality and integrity concerns, inconsistent platform implementation, and difficulties with getting assistance with technical or data quality issues.

4.7.1. Data Access Fees

Access to system data – such as hosting capacity, distributed generation queued for interconnection, installed distributed generation and other previously mentioned available system data – are available without a fee. The UER populates community wide aggregated energy usage information and is available to the public free of charge. Staff believes that access to this information increases transparency to the market and lowers barriers to entry for new products and programs. In connection with the proposed Data Access Framework, which would create a centralized and automated process for data access, Staff recommends abolishing all data fees, including the fees for CCA related data.

4.7.2. Data Quality and Integrity

Defining the necessary steps and requirements for an ESE to obtain access to energy-related data is necessary to enable the sharing of useful energy data. However, without establishing requirements for the quality and the integrity of the data being shared, the usefulness of that data may be lost. While Staff acknowledges that each utility is operating with different IT systems, the differences in how the data are being recorded on the utility side does not necessarily prevent the ability to provide standardized data as an output. Energy-related data should be portable, and customers need to have the ability to share their data with any ESE, through whatever means they have chosen. For that to happen, available energy usage should be made available in a standardized manner. Along these lines, Staff seeks stakeholder input as to what data quality and integrity standards should be considered, as well as what type of metrics can be used as a means to determine if these standards are working.

[40] Cybersecurity Order, p. 64.

4.7.3. Reporting

Accountability and Auditing

As with data access, annual reporting requirements have been established in multiple proceedings and in some cases, like GBC reporting, the requirements have been included in rate case proceedings. In consideration of the many areas that may have existing reporting requirements, Staff proposes to incorporate all the reporting requirements into one primary reporting matrix. This would ensure that all the necessary components are available for the proper evaluation of access to energy-related data. Staff seeks input from stakeholders as to the frequency of any required reporting, as well as whether there are specific metrics that should be captured for determination of the success of this Data Access Framework.

4.8. Data Access Framework Continuous Improvement

The proposed Data Access Framework is designed to be flexible when it comes to changing needs. This Data Access Framework is grounded in a risk-based approach to security and privacy which requires continuous review and modification to address new threats or risk, and the necessary protections to mitigate these risks. Staff recommends annually convening a Data Access Market Participant Input Session to allow input and collaboration from ESEs, utilities, and other market participants. Staff could then make recommendations for modifications to the proposed Data Access Framework to the Commission based upon those meetings if necessary. In the event there is an immediate need for a modification to the proposed Data Access Framework, the Commission could take short term measures to allow immediate action on items that pose a security concern and are unable to wait for the annual review process.

4.9. Customer Sharing of Energy-Related Data

The proposed Data Access Framework, as discussed above, would not meet its full potential of enabling useful access to useful data without first establishing mechanisms that (a) facilitate customers' ability to easily consent to share their data and (b) educate and engage customers as a means to encourage customer consent to data sharing. Additionally, further exploration of opt-out strategies could prove to be beneficial. The power of unlocking useful data lies in the customer's hand. Staff's recommendations on this topic considers a balance between informed consent and the value of sharing data. The Commission's Cybersecurity Order recognized that the data are the customers' data and that customers have a right to direct or consent to the use of their data. Simply put, they are the ones who determine what happens with their data, not the data custodian.

While there has been a substantial amount of work put into establishing the UBPs' consent requirements, including the process of obtaining consent, these requirements only govern the interaction between customers and ESEs for general purposes (enrollment and billing). The existing requirements include, among other things, ensuring that the ESE is providing the necessary information for the customer to provide informed consent, and for such consent to be deemed valid. The discussions below do not address these existing requirements found in the UBPs. Instead, the discussions around consent pertain to a customer's ability to consent for other purposes, through alternative means. For example, a customer may use GBC to consent to share his or her data with an energy efficiency provider for the purpose of identifying potential products or services the customer may benefit from. The customer and ESE interaction options and requirements in this example would not be determined by the UBP. Currently, there is no guiding document or policy that establishes overall requirements that apply for consent outside of general purposes.

Need for Consent

To enable the market for new products and services, there is a need for CEUD. To maintain the privacy of customer data, the data custodian (e.g., the utility or a data warehouse) must have the necessary cybersecurity and privacy protections in place to adequately maintain the security of customer data. Highly confidential personal information, such as social security numbers and financial information should never be shared, however, an authorized ESE can be provided with customer contact information and usage information upon the consent of the customer.

Since the terms of the consent agreement are between the customer and the ESE, the need or purpose of that data request need not be provided to the data custodian. The ESE's purpose for accessing data would be validated through the Data Ready Certification process. To facilitate this consent process, some states, such as Texas and California, have a common consent form across the utilities. Staff recommends establishment of universal consent mechanisms that would ensure all participants in the process, including the customer, have a clear and common understanding of terms and requirements for informed consent that allows energy-related data to be shared. Consent mechanisms should not be implemented in a way that imposes unreasonable barriers to customer choice. Without specific requirements that ensure consistent processes and treatment, regardless of utility, mechanisms established to enable customers to easily consent to share their data will not be effective. As such, standardized mechanisms for consent, should be developed to ensure a common application and process for customers, ESEs, and utilities across New York State.

While utilizing a web-based process with as few steps as possible is preferred, would keep the customer engaged, and would facilitate the consent process, other consent options should be developed for those who do not have electronic means available or who choose to use alternative methods. While providing consent through traditional means (i.e. signing an agreement and mailing it in) may delay the customer process and can result in a customer having a less convenient experience, the option should be made available for those who choose to use these means.

Options should be explored for development of multiple standardized options for a customer to provide consent. For example, many customers are familiar with internet-based commerce and permissions.

Customers can login to secure web sites using authentication from other sources, such as using a Google or a Facebook password. Therefore, rather than requiring customers to use their account numbers for authentication, customers could instead potentially use their utility log-in information. This method of authentication maintains the customer consent process because each landing page throughout the process requires information only held by the customer.

Expectations of Consent

Expectations of privacy and consent are evolving. A customer who is uninterested in new apps, services, or offerings may be unlikely to support having his or her data be made available and provide consent. A customer interested in the newest technology offerings may have less concerns about the privacy of his or her CEUD. The consent agreement should be developed in a way that enables customers to exercise control over their consent by: addressing customer choice; defining the data being shared, for what purpose, and for how long; allowing the customer the ability to revoke consent; requiring additional consent for any purposes outside what was originally specified; and ensuring consistency with requirements existing under the Data Ready Certification model. Other requirements that would traditionally be dictated by the consent agreement would be incorporated into requirements under the Data Ready Certification. This would reduce the necessary information a customer will have to read and understand in order to complete a consent agreement. An authorized ESE might only need monthly data for the past six months, in which case, the customer should be made aware and ensure that only six months of monthly data are provided to the ESE subject to his or her consent.

Customer Options

The principle of customer control should be considered when evaluating the types of data and various uses of customer data. Customers should be able to condition the use of their data beyond whatever is needed to provide utility service. Customers should be able to choose to allow their data to be shared with individual authorized ESEs as well as afforded the option to choose to share their data openly with all authorized ESEs. Empowering utility customers in these ways reflects the changing cultural perspectives on the value of customer data and recognizes an increased consumer understanding of their rights to control what happens with their data. Nevertheless, customers should be made aware of their right to opt-out of having their data shared in certain situations. For a utility to provide service, it must do several things - forecast demand, contract for electricity, generate a bill, install a new meter, maintain service and equipment, and so forth. A utility may also develop other customer programs or evaluate existing programs which will make use of customer data. Staff seeks further input as to the situations in which customers should be afforded the opportunity to opt-out of having their data used, including use by the utility to develop new products and services, as well as having their data included in a larger aggregated dataset that keeps the customer's identity anonymized.

Opt-Out Approaches

Utilities play a critical role in achieving on New York's ambitious clean energy policy objectives, delivering robust programs to reduce carbon emissions, increase system reliability, and save money for participating consumers. Opt-out strategies, or providing to consumers an opportunity to decline participation rather than proactively seek it, have been successfully deployed to increase the participation rates for various programs and policy objectives. For example, New York's CCA program has demonstrated how opt-out enrollment can benefit both customers and the communities they reside in. To date, CCAs, on average, have offered savings in energy supply costs, allowed for a cleaner energy supply and, perhaps most importantly, have helped customers become informed consumers. CCAs in New York State saw a 16.5% opt-out rate during program initiations.[41]

Staff proposes further piloting this concept for the purpose of sharing CEUD to advance clean energy goals. Any such pilot must have a well-defined duration, must clearly communicate to consumers what data will be shared, with whom and for what purpose it will be shared, and must have a clear process for allowing consumers to decline participation or opt-out. Possible approaches may include providing an opt-out opportunity at the time service is established, when a customer signs up for a time-of-use (TOU) rate or community distributed generation (CDG) program, when a customer makes a purchase from a utility's marketplace, or when a customer participates in a rate-payer funded energy efficiency program. Staff seeks market participant input on how best to develop such a pilot including criteria to use to ensure consumers are provided appropriate notice and opportunity or opt-out.

5. Implementing the Solution

The proposed Data Access Framework defines the process for access to energy-related data, recognizes customers' right to consent to share their energy usage data, encourages customer control of their energy-related data, supports the requirements of in the Commission's Cybersecurity Order, provides standard definitions of key data-related terms, establishes and ensures data quality and integrity standards, and creates an easy to understand Data Access Framework Application Guide that outlines the necessary steps to obtain access to energy-related data in a uniform and consistent manner.

Only through addressing and including all the components detailed above, will the true value, and benefits of, access to energy-related data be fully unlocked. The implementation of the proposed Data Access Framework is designed so as to not place burdensome requirements upon any party.

As discussed throughout this whitepaper, the necessary cybersecurity and privacy requirements have already been determined throughout numerous proceedings. These requirements have already

[41] Consumers residing in a CCA municipality are provided notice that a CCA will be instituted and provided an opportunity to decline participation.

received Commission approval for use, and the existing roadblock is not the accuracy of the requirements, it is in the accurate assignment of risk and inconsistent implementation of such requirements. Implementation and application of this Data Access Framework will require actions of both Staff and utilities for it to be successful. A necessary output of the framework is a mapping of the existing cybersecurity and privacy requirements to the various combinations of purpose, access mechanism and data type that can result from application of the Data Access Framework (i.e. the matrix). Creation of such cybersecurity and privacy requirement matrix will require a detailed examination of all existing requirements, accounting for duplicative and inconsistent requirements, and reviewing for correct risk assignment. This matrix would then be used to determine the required cybersecurity and privacy protections for Data Ready Certification and would replace the existing utility side requirements for ESEs seeking access to energy-related data. Staff proposes that the cybersecurity and privacy matrix compile existing requirements and identify and assign the necessary requirements for ESE access to energy-related data.

Staff notes that the proposed Data Access Framework does not place additional requirements upon utilities for the determination of necessary requirements or validation of the requirements being met. Adoption of the Data Access Framework is expected to reduce the amount of time and resources the utilities would need to allocate in order to ensure an ESE has the appropriate protections in place. The implementation of the proposed risk-based ESE Data Ready Certification program completely removes the utilities informal oversight role and correctly moves it to the Provider, for a uniform and consistent application.

6. Closing

This proposed Data Access Framework would establish a clear set of requirements that must be implemented to ensure the appropriate protections are in place for access to energy-related data while also enabling the means by which customer access and data sharing can occur. Staff believes that this Data Access Framework would provide utilities, customers, and ESEs with a set of expectations on process which would support a marketplace of ideas and innovation. This would further ensure that the experiences and expectations of the customers and ESEs are substantially the same throughout the State. This would allow ESEs to craft one set of business practices that can be used across the State rather than crafting individual business practices for each utility service territory, thus potentially reducing ESE costs related to customer acquisition and implementation of cybersecurity and privacy controls.

Staff is asking the Commission to adopt a statewide Data Access Framework that includes the following:

- A framework that serves as a single source for data access and provides uniform and consistent guidance on what is needed for access to, and the availability of, energy-related data. This framework would incorporate all existing data access requirements, including cybersecurity and privacy requirements.

- A Data Access Framework Application Guide that conveys the necessary steps for obtaining access to data.
- The implementation of an ESE risk management program that provides a Data Ready Certification. The ESE risk management program would be responsible for the verification and certification of ESE cybersecurity and privacy requirements.
- Standard definitions of key data-related terms.
- The development of data quality and integrity standards.
- Customer consent requirements.
- An Opt-out pilot program.
- Reporting requirements.

If the proposed Data Access Framework is adopted, Staff recommends that each utility should be directed to make a compliance filing that includes the details and verification of how each has updated all existing policies and requirements to be consistent with the Data Access Framework.

In addition to the individual utility compliance filing, Staff recommends a subsequent Joint Utilities filing, for Commission review and approval. The joint filing should include:

- a proposal for an alternative method of account identification when completing ESE customer transactions that have traditionally relied on the customer account number for that purpose;
- an implementation proposal for the ESE risk management program, managed by a Provider, and includes the Data Ready Certification program; and
- an implementation plan detailing how the JU will implement a centralized certification model that any ESE will be able to access, and that will only have to be done once, regardless from which data custodian the ESE is seeking to access data, until the ESE risk management program and Data Ready Certification is fully operational.

Finally, Staff intends to file with whitepaper for public comment. When submitting comments, Staff urges stakeholders to utilize the organizational structure of this whitepaper in order to facilitate the analysis of issues presented in each section.

Definitions of Key Data-Related Terms

Access Role

The access role is determined through the Data Ready Certification process and details the exact data sets and transmittal/access methods through which the ESE is approved to access energy-related data.

Aggregated Data

Aggregated Data are a combination of data elements from multiple accounts to create a data set that is sufficiently anonymized as to not allow for the identification of an individual account or customer.

Anonymized Data

A data set containing individual sets of information where all identifiable characteristics and information including, but not limited to, name, address, or account number, are removed (or scrubbed) so that one cannot reasonably re-identify any individual customer within the data set.

Customer Billing Data Set

The Customer Billing Data Set includes the necessary account information to facilitate enrollment and billing of the customer's account.

Customer Contact Information Data Set

This data set contains information that is specific to the individual and should only be available for ESEs that are requesting access for a valid purpose including: (1) providing or reliably maintaining customer-initiated service; (2) including compatible uses in features and services to the customer that do not materially change reasonable expectations of customer control and ESE data sharing; or (3) providing pursuant to Commission Order and/or State, Federal and Local Laws or regulations, or upon customer consent. The following data elements are to be considered part of the Customer Contact Information Data Set: customer of record's name(s); service address; mailing address; phone number; and primary language, if available, as well as any customer-specific alternate billing name, address, and phone number. The separation of this data set provides the necessary details to facilitate the request for customer consent while protecting customer privacy and recognizing a customer's choice to share his or her data.

Customer Data Sets

Eligible customer data are separated into three different data sets: customer contact information, customer billing, and customer energy usage.

Customer Energy Usage Data (CEUD) Set

CEUD is the data generated by a meter, for example, that describes a customer's usage. This data can be in kilowatts, kilowatt/hours, or any other data that the meter collects, such as voltage or current. This information can also include the rate a customer is on, and other billing determinants, such as bill cycle.

Cybersecurity Protections

Risk mitigation controls implemented to address the risk to IT systems and the data they house.

Data Custodian

Where the energy-related data are housed and being accessed, such as from the utility or from a centralized data warehouse.

Energy Service Entities (ESEs)

Any entity (including, but not limited to, ESCOs, DERs, and CCA Administrators) seeking access to energy related data. In limited circumstances, the utility may also be an ESE.

Highly Confidential Personal Information

Highly sensitive information specific to an individual that could be used to identify the individual, such as social security number, banking information, or driver's license. This information should not be shared under any purpose and is not used for transactions related to access to energy-related data.

Historical Data

Historical data are the most recent Customer Energy Usage Data, preferably while at the same address and for at least 12 months. Historical data are used to analyze impacts of a particular technology or program and extrapolate that into the future.

Privacy Protections

Risk mitigation controls that are implemented to address the privacy risks of the data.

Real Time Data

Data collected via Advances Meter infrastructure that is presented in 15-minutes increments, or less.

System Data

System data are information about components and activity at the distribution system level.

NEW YORK STATE OF OPPORTUNITY. | Department of Public Service

Case 20-M-0082- Proceeding on Motion of the Commission Regarding Strategic Use of Energy Related Data

Department of Public Service Staff Whitepaper
Recommendation to Implement an Integrated Energy Data Resource

Dated May 29, 2020

Contents

1 Purpose and Scope

Under the Reforming the Energy Vision (REV) comprehensive energy strategy, New York is transforming its electricity system into one that is cleaner, more resilient, and more affordable.[1] Useful access to useful energy data will play a critical role in this transformation. Unleashing the power of energy data will speed the deployment of clean energy solutions by attracting investment, enabling analytics, identifying operational efficiencies, promoting innovation, and encouraging new business models, which will in-turn create value for customers and the State's energy system.

The New York State Public Service Commission (Commission) directed Department of Public Service Staff (Staff) to "file a whitepaper regarding the creation of an integrated energy data resource that would provide a platform for access to customer and system data."[2] The Commission further directed Staff to consider energy data initiatives in other in other jurisdictions and to include recommendations for stakeholder engagement, data resource design, data resource use cases, implementation, and operation.[3]

This whitepaper begins with background information regarding relevant regulatory actions in New York State, including a Commission-directed pilot Distributed Energy Resource (DER) data platform that was implemented recently under the oversight of Staff and the New York State Energy Research and Development Authority (NYSERDA).[4] This whitepaper also considers a recent DER industry group initiative that advocates for rapid development of a centralized data platform containing utility-sourced information that would be useful to DER providers and other stakeholders.[5] The whitepaper then describes and assesses the existing energy information framework in New York State; identifies and characterizes notable energy data initiatives in other states; and, proposes a plan to develop and operate an Integrated Energy Data Resource (IEDR) for New York State.

1 See generally, Case 14-M-0101, Reforming the Energy Vision.

2 Case 20-M-0082, Strategic Use of Energy Related Data, Order Instituting Proceeding (issued March 19, 2020) (Instituting Order).

3 Instituting Order, p. 7.

4 Case 18-E-0130, In the Matter of Energy Storage Deployment Program, Order Establishing Energy Storage Goal and Deployment Policy (issued December 13, 2018) (Storage Deployment Order).

5 Case 14-M-0101, In the Matter of Distributed System Implementation Plans, Summary Report: Distributed Energy Resource Market Enablement Data Needs (filed as a Public Comment January 6, 2020).

In the most general terms, Staff recommends that the IEDR collect and integrate a large and diverse set of energy-related information on one statewide data platform. The types of information made accessible through the IEDR should provide useful insights related to the provision and use of electricity and natural gas in New York State. To advance development of a statewide IEDR, Staff recommends that the Commission specify the IEDR's purpose, scope, and capabilities, and establish frameworks for funding, program management, and governance.

2 Background

2.1 New York State Regulatory Actions Relevant to Energy-Related Data

The REV Track One Order acknowledged the importance of data availability for the future adoption of DER and customers' management of their energy usage.[6] Acting on this, the REV Track One Order established a policy framework to develop DER markets and advance State clean energy goals. In doing so, the Commission called for a single, uniform platform for retail market access throughout New York that would also serve as a statewide market for REV-enabled products and services.[7] The Commission intended for REV to establish markets so that customers and third parties can be active participants in the new, dynamic energy grid; resulting in a more efficient and secure electric system with better utilization of distribution, bulk generation, and transmission resources. Through this market animation, DERs will become integral tools in the planning, management, and operation of the electric system. Developers will be able to monetize the value of DERs in this market, allowing DERs to compete with more centralized options. Furthermore, customers will be able to create new value opportunities while improving system efficiency by exercising choices within an improved electricity pricing structure.

To enable these markets, the Commission described New York's investor owned electric utilities[8] as transitioning from the historical model of a unidirectional electric system, serving an inelastic demand, to a more dynamic, bidirectional system including a modernized infrastructure, price-reactive loads, and, greatly enhanced capabilities for acquiring,

6 Case 14-M-0101, Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26,2015) (REV Track One Order).

7 Id., p. 63.

8 New York's investor-owned electric utilities are: Central Hudson Gas and Electric Corporation (Central Hudson), Consolidated Edison Company of New York, Inc. (Con Edison), New York State Electric & Gas Corporation (NYSEG), Niagara Mohawk Power Corporation d/b/a National Grid (National Grid), Orange and Rockland Utilities, Inc. (O&R), and Rochester Gas & Electric Corporation (RG&E) (collectively, the Joint Utilities). The requirements of the IEDR are applicable to all jurisdictional utilities in New York, including natural gas utilities.

communicating, and managing data. The REV Track One Order deliberated on many issues and options including, but not limited to, stakeholders' needs for different types of data (e.g., system and customer data) to enable markets, data accessibility, cybersecurity, and the creation of an independent data exchange. At the time of the REV Track One Order, many parties suggested, and the Commission agreed, that the idea of a separate data exchange was premature; however, the concept of an independent data exchange remained a longer-term goal to be explored as the grid and markets evolved to fulfill REVs goals.[9]

To guide this transformation of the utility model, the Commission defined a set of functions that a modern utility, which the Commission termed a Distributed System Platform (DSP), should perform. The REV Track One Order required each utility, as a future DSP, to periodically file a comprehensive Distribution System Implementation Plan (DSIP) that includes detailed information about the utility's existing and planned capabilities for providing useful, market-enabling data to customers and third parties.[10]

On April 20, 2016, the Commission issued an order adopted guidance for the organization and contents of the Joint Utilities' DSIPs.[11] The DSIP Guidance Order made clear that useful data is needed to encourage market animation and drive DER penetration. The Commission stated that:

> …barriers to DER entry need to be removed. Addressing the information imbalance that currently exists will help remove such barriers. Today, there is very little information available to DER providers regarding the value of, or cost to, site resources in any particular area of the distribution system, or what type of resources or operational characteristics would have the most value. The system data supplied should bring together the information that DER providers will need to locate resources in areas of the system that will produce the most value. Utilities should work with stakeholders to address the types and levels of data to be provided, the methodology and rules for providing system data (including addressing security concerns), and frequency of updates.[12]

[9] REV Track One Order, p. 58.

[10] Id., p. 59.

[11] Case 14-M-0101, Order Adopting Distributed System Implementation Plan Guidance (issued April 20, 2016) (DSIP Guidance Order).

[12] Id., p. 41.

Staff provided the Joint Utilities with more detailed DSIP guidance in a May 2018 whitepaper,[13] further emphasizing the importance of customer and distribution system data. The DSIP Guidance Whitepaper stated that:

> [m]aintaining a full and timely exchange of DSIP information between the utilities and stakeholders is critical to achieving the most beneficial deployment and use of DERs. Key areas of emphasis should include: the purposeful development of stakeholder tools and information sources useful to DER providers in fostering productive DER development; collecting, managing, and sharing system and customer data; and, advances toward an integrated planning environment.[14]

Since launching REV, the Commission has continued to work on numerous data-related initiatives encompassing both customer and system data access. Nonetheless, DER providers and customers are still unable to efficiently access most of the data that would be useful to them. Without such access, the State will not be able to implement the dynamic, reactive, and efficient distribution system envisioned in REV. This whitepaper proposes next steps to enable access to useful energy data.

2.2 Pilot Data Platform

The Storage Deployment Order directed Staff and NYSERDA to lead coordination efforts with the Joint Utilities, Long Island Power Authority (LIPA), New York Power Authority (NYPA), and other stakeholders to develop and implement a Pilot Data Platform (Pilot Data Platform) with the assistance of a third party platform provider.[15] The Energy Storage Order highlighted the need to acquire, organize, and enable developer queries of the interrelated customer and electric system data in ways that help them more efficiently identify storage and/or DER development opportunities that best fit their objectives.[16] The Energy Storage Order also emphasized the need for masking and other security measures to protect customer and electric system data from unauthorized access. The Commission established the goal of implementing an operational platform by December 31, 2019 and suggested exploring the possibility of using the NYPA New York Energy Manager (NYEM) or another available resource to accelerate the initial development of the platform.[17]

[13] Case 16-M-0411, DPS Staff Whitepaper, Guidance for 2018 DSIP Updates (issued May 29,2018) (DSIP Guidance Whitepaper).

[14] Id., p. 5.

[15] Case 18-E-0130, Storage Deployment Order, Ordering Clause No. 12.

[16] Id., p. 85.

[17] Id., p. 84.

NYSERDA and Staff initiated the project by first defining the Pilot Data Platform's functional objectives and then establishing the scope of work. Those initial efforts determined that the Pilot Data Platform, its associated operating processes, and its associated interactions with users and data sources shall provide the means and methods to:

- enable complex, developer-designed, select queries across all categories of customer and system data stored in the database;
- prevent unauthorized identification of customers;
- prevent unauthorized identification of system elements;
- comply with appropriate cybersecurity protections, such as potential Data Security Agreements;
- enable automatic consent requests or data transfers if consent was previously received; and,
- allow for the evolution of data sets within the platform, including updating data over time, adding categories of data, and reformatting data masking protocols if needed.

Staff and NYSERDA then met with NYPA in February of 2019 and mutually determined that it would not be practical to use the NYEM as the Pilot Data Platform. However, Staff and NYSERDA suggest that consideration could be given to NYEM in the future for broader platform rollout.

To select an investor-owned electric utility for participation in the Pilot Data Platform, Staff and NYSERDA determined that the participating utility must: currently collect and store many/most of the desired data types identified below; serve an area with active DER development; have the necessary Information Technology (IT) capabilities in place; and be willing to process and transfer the required data sets. Based on those criteria, Staff and NYSERDA selected Orange and Rockland Utilities (O&R) to be the participating Pilot Data Platform utility. O&R has many of the necessary participating utility qualities, such as: they operate in a downstate New York Independent System Operator, Inc. (NYISO) zone where energy storage and other DERs have more value; they have deployed advanced metering infrastructure (AMI) so have more interval data; and, they serve an area with diverse demographics.

Informed by the insights gained through extensive developer interactions during development of the Energy Storage Roadmap,[18] NYSERDA and Staff determined that the types of interrelated customer and system data useful to DER developers would include details related to (but not be limited to) substations, circuits, service points (electric and gas), customers (electric and gas), buildings, DERs, and electric vehicles (EVs). A detailed breakdown

[18] Case 18-E-0130, New York State Energy Storage Roadmap and Department of Public Service / New York State Energy Research and Development Authority Staff Recommendations, (filed June 21, 2018) (Energy Storage Roadmap).

of the data items within these categories (as well as several other categories recommended for the IEDR) is provided in Appendix B.

O&R and the selected third party contractor, Trove Predictive Data Science (Trove), jointly determined the Pilot Data Platform's initial dataset, which was limited to a subset of the above items to reduce complexity and streamline development and testing. DER developers were called on for input throughout the process, as well as to test and evaluate the functionality and usefulness of the Pilot Data Platform's capabilities.

Development and rollout of the initial Pilot Data Platform was successfully completed on-time and at a cost of approximately two hundred and forty thousand dollars. DER industry members were subsequently invited to: register as Pilot Data Platform users; test the Pilot Data Platform's functions and features; share details about their user experiences; provide their assessments of the Pilot Data Platform's usefulness as a resource for identifying opportunities to deploy and/or operate DERs; and, suggest changes and/or additions that would enhance the Pilot Data Platform's value to them. At the time of filing this whitepaper, more than 24 DER developers have registered as users and begun testing the Pilot Data Platform. Aside from identifying a few minor glitches – which were readily resolved – the user comments received so far have been very positive.

The Pilot Data Platform is performing as anticipated and Staff suggests that further development of the resource will be useful and informative. Staff is encouraged by O&R's participation and by Trove's capabilities and expertise. Full-scale implementation of a resource that expands on the scope and functionality of the Pilot Data Platform has the potential to be a ground-breaking tool for the DER market and the clean energy industry.

2.3 DER Industry Data Initiative

In March 2019, a group of DER industry members and consultants (the DER Industry Group) commenced an effort to examine and report on the role of data in animating the markets for DER products and services envisioned in REV. The group periodically received input from Staff and NYSERDA in an effort to maintain alignment with current and future State policies and programs.

<u>Purpose of the DER Industry Group Report</u>

The DER Industry Group's report[19] focuses primarily on the industry's need for grid, market, and customer information from utilities; the shortcomings of the existing collection of disparate utility information sources available to industry stakeholders; the composition and benefits of a minimum viable data set (MVDS) comprising the most basic set of utility-sourced information needed to accelerate DER market animation; and, the advantages and

[19] Case 16-M-0411, Summary Report: Distributed Energy Resource Market Enablement Data Needs (filed in the public comments section on January 6, 2020).

characteristics of a centralized and highly standardized data platform populated first with the MVDS and then with additional types of information useful to the DER industry and other stakeholders.

To make clear the value of their recommendations, the DER Industry Group report describes a variety of information use cases that would help DER industry members to identify DER development opportunities and plan DER solutions that are well-aligned with their capabilities and business objectives. The use cases described in the report seek to identify and characterize opportunities based on utility customer needs and interests, grid needs identified independently by developers, and utility-identified grid modernization needs. Through their evaluations of those use cases, the industry group identified and characterized the MVDS data elements needed to enable efficient and effective implementation of those use cases by the market participants. All of the DER Industry Group's recommended MVDS data elements are included in Staff's recommended set of IEDR data items listed in Appendix B.

The anticipated benefits of the centralized and highly standardized data platform advocated for in the report include improved information visibility and integrity resulting in greater confidence in statewide system planning, policy development, and regulatory proceedings. The recommended approach will also streamline customer and third party engagement through data analytics and improve industry members' ability to create and implement new markets.

The Minimum Viable Data Set (MVDS)

The DER Industry Group's report identifies three categories of data needed to enable the key DER developer use cases: grid condition and performance data; business case and market data; and, customer data.[20] According to the DER Industry Group, having enough data in each of these categories would materially improve DER providers' ability to identify locations where DERs can provide the most value to customers and/or the grid. Furthermore, the industry group explains that the MVDS proposed in the report would improve DER providers' ability to accurately calculate and optimize business cases for DER investments that maximize value to investors and customers. The report summarized the MVDS in the following table:

Figure 1: MVDS Data Categories and Elements

[20] Id., p. 7.

Grid Condition/Performance Data	Business Case/Market Data	Customer Data
System Elements	Distribution Network Value – Tariff	Customer Class
Hosting Capacity Analysis	Distribution Network Value – Non-Wires Solution	Tariff
Network Demand	Bulk Power Market Value	Bill
Voltage & Power Quality	Distribution Investment Plan	Interval Usage
Reliability Statistics	Other	Location

To maximize the usefulness of the MVDS to market participants, the industry group report notes that the meaning, format, attributes, and integrity of data elements from across New York State should fully comply with standard specifications that are compatible with applicable national standards or practices. The report further notes that the timely updating of all data elements, based on the requirements of the MVDS use cases, is necessary to ensure MVDS usefulness.[21]

The DER Industry Group found that most of their recommended MVDS data elements are available and accessible in today's data environment, but that a DER developer must acquire needed data from disparate sources. According to the DER Industry Group, the significant differences in the meaning, format, attributes, and integrity of their respective data is an inconsistency that presents a barrier to DER market animation as it severely hinders DER developers' ability to effectively and efficiently use the data that they obtain from those sources. The following table from the report summarizes the industry group's assessment of current MVDS data availability:

Figure 2: Current Availability of Recommended MVDS Data Elements

[21] Id., p. 10.

Grid Condition & Performance Data	Status	Business Case & Market Data	Status	Customer Data	Status
System Elements	Partially Available	Distribution Network Value – Tariff	Available	Customer Class	Available
Hosting Capacity Analysis	Partially Available *	Distribution Network Value – Non-Wires Solution	Partially Available	Tariff	Available
Network Demand	Partially Available *	Bulk Power Market Value	Available	Bill	Available
Voltage & Power Quality	Partially Available *	Distribution Investment Plan	Available	Interval Usage	Partially Available *
Reliability Statistics	Available	Other	Available	Location	Available

Available   Partially Available   Not Available   * Improved/Available w/ AMI

The industry group report argues that the current "federated" data environment in New York State is not fulfilling the REV objectives for providing DER developers and other stakeholders with data that enable DER market animation.[22] Participants in the initiative reported that the structure and contents of today's data ecosystem are primarily utility-oriented rather than market-focused. They further describe a "…disjointed and opaque data environment"[23] in which data are often hidden behind multiple layers of access; are encoded, stored, and presented with inconsistent characteristics (even within a single utility); and, are updated too slowly and/or irregularly.

To resolve the shortcomings of the current data environment, the DER Industry Group recommends combining all MVDS data elements into a centralized platform from which DER developers and other stakeholders can acquire data that are uniform, current, and accurate. According to the DER Industry Group, such a platform would enable efficient and effective holistic data analyses that are very difficult to perform using the current environment.

Finally, the DER Industry Group recognized the burden associated with creating a centralized data platform and noted that there is no mechanism for the Joint Utilities and the market to transition from the current decentralized environment to a centralized framework. The report further notes that the new platform should align with and incorporate the results of any ongoing relevant data access efforts in the State, such as the Pilot Data Platform described earlier in this whitepaper.

[22] Id., p. 26.

[23] Id., p. 13.

3 The Current State of Access to New York State Energy Information

When REV was initiated in 2014, the grid and the business operations of the Joint Utilities provided one-way distribution of electrical energy produced mostly by large, centralized generating plants. There were few provisions (if any) in this traditional operating model for efficiently planning, interconnecting, and operating large numbers of widely distributed DERs. Any sharing of the utility system and customer data with non-utility entities was minimal, at best.

To enable REV's objectives, the Commission ordered the Joint Utilities to implement a new operating model that, among other things, provides DER developers, energy consumers, and other grid stakeholders with efficient access to a wide variety of useful grid and market information. Based on the Commission's instructions[24] and guidance from DPS Staff,[25] the biennial DSIP filings describe the Joint Utilities' current status and plans for timely and efficient sharing of useful data. Unfortunately, the data sharing achievements and plans reported in the DSIPs, and the progress observed by stakeholders and Staff, have fallen well short of the Commission's directives.

3.1 Existing Energy Data Resources

While useful access to useful energy data has not yet been achieved, the variety and volume of system and customer data now available from the Joint Utilities and other providers has increased when compared with the minimal amount of data available in 2014. The following subsections describe the data resources currently available to DER developers, energy consumers, and other grid stakeholders.

3.1.1 Utility System Information Portals

Since 2016, each of the Joint Utilities has separately implemented, enhanced, expanded, and maintained one or more online portals for sharing useful electric system information with DER developers and other industry stakeholders. The types and attributes of shared information, and the methods for sharing the information, have been both prescribed directly by the Commission and determined through a Commission-directed stakeholder engagement process that is led by the Joint Utilities. Following are the categories of system information currently available online for each utility:

- Distributed System Implementation Plans (via the DPS DMM platform)
- Capital Investment Plans (via the JU web site or the DPS DMM)
- Planned Resiliency/Reliability Projects (via the JU web site or the DPS DMM)
- System Reliability Statistics (via the utility's web sites or the DPS DMM)
- Hosting Capacity (via the utilities' web sites)

24 Case 14-M-0101, DSIP Guidance Order.

25 Case 16-M-0411, DSIP Guidance Whitepaper.

- Beneficial Locations for DERs (via the utility or JU web site, the DPS DMM, or none)
- System Load Forecasts (via the utility web sites, or none)
- Historical System Load Data (via the utility web sites, or none)
- Opportunities for Non-Wires Alternatives (via the utility web sites, or none)
- Distributed Generation Queued for Interconnection (via the DPS public web site)
- Installed Distributed Generation (via the DPS public web site)
- System Interconnection Request (SIR) Pre-Application Info (via the utility web sites)

Web links to all the utilities' online system information sources are publicly accessible via the System Data page of the Joint Utilities of New York web site.[26] A consolidated inventory of those links is provided in Appendix A.

Currently, the structure, attributes, semantics, availability, and accessibility of the information from many of these sources vary significantly across the utilities. In addition, these sources provide little of the information related to EV loads and energy storage that was specified in Staff's 2018 DSIP Guidance. Finally, and very importantly, only the few sources pertaining to DER interconnections provide any sort of association between a utility customer and the system infrastructure that serves that customer.

3.1.2 Utility Customer Data Portals

Along with requiring the Joint Utilities to share useful system information, the Commission's REV Orders sought to ensure that the Joint Utilities implement means and methods for providing useful customer-specific information to DER developers and other grid stakeholders. Those means and methods for providing useful data are required to include adequate provisions for protecting customers' personally identifiable information (PII) and for obtaining customer consent to allow third party access to any of that information. As the amount of data generated by the grid and ratepayers has increased, the use and ownership of that data has become the subject of debate and numerous regulatory actions nationwide. The Commission has provided guidance that this data is owned by ratepayers, not ratepayer-funded utilities, and it is a priority to protect ratepayers' rights regarding this data.[27]

[26] Available at: https://jointutilitiesofny.org/system-data/.

[27] Case 18-M-0376, Proceeding on Motion of the Commission Regarding Cyber Security Protocols and Protections in the Energy Market Place, Order Establishing Minimum Cybersecurity and Privacy Protections and Making Other Findings (issued October 17, 2019), pp. 13, 47.

Detailed time-series interval data describing customer energy consumption is particularly useful for several purposes. Other types of useful customer-specific information envisioned for sharing include (but are not limited to) customer category, service address, service voltage, service configuration, billing rate, meter type(s), NYISO zone, NYISO transmission node, substation, substation transformer ID, distribution circuit, circuit phase(s), distribution transformer ID, local hosting capacity, DER details, EV charging details, applicable NAICS code, building characteristics, municipality, and applicable zoning.

Thus far, the Commission's emphasis and Joint Utility efforts have focused on providing the data that describe each customer's energy consumption and promoting more efficient and productive access to those data by DER developers and other grid stakeholders. To advance progress towards that goal, the Commission directed[28] the Joint Utilities to implement highly standardized online customer data sources based on, or equivalent to, the Green Button Connect (GBC) standard.

GBC is a format, access, and interface standard for energy consumption data that provides energy customers (electric and gas) and authorized third partieswith access to the customers' energy usage data. Energy data providers that comply with the GBC standard uniformly provide user-friendly and computer-friendly data access that is consistent from one provider to the next. Widespread GBC implementation by energy utilities should enable third party energy product and service providers to significantly increase the speed and efficiency of their marketing, sales, and operations.

Importantly, a utility's ability to timely provide detailed energy usage data for customers (both electric and gas) is contingent on the utility's use of smart meters at the customers' premises. Timely acquisition of data from those smart meters requires AMI. Currently, just two of the Joint Utilities, Con Edison and O&R, have widely – but not yet fully – deployed AMI in their service territories. National Grid, NYSEG, and RG&E are at varying stages of planning, funding, and initiating AMI deployment. Meanwhile, Central Hudson has decided not to deploy smart metering widely in its service territory.

To date, only Con Edison and O&R have implemented GBC. On October 15, 2019, the Joint Utilities filed a Status Report on Green Button Connect My Data with the Commission.[29] The JU summarized the status of GBC in New York is as follows:

[28] Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative, Order Adopting Accelerated Energy Efficiency Targets (Issued December 13, 2018) (Accelerated EE Order).

[29] Case 18-M-0376, Proceeding on Motion of the Commission Regarding Cyber Security Protocols and Protections in the Energy Market Place, Joint Utilities Report on Green Button Connect My Data (filed October 15, 2019).

- Con Edison and O&R have implemented GBC in a manner that does not fully comply with the GBC standard. Only three third parties have completed the registration process and are permitted to receive customer consent to acquire customer data. An additional ten third parties are in various stages of the registration process.
- Central Hudson does not offer GBC but offers Green Button Download My Data.
- National Grid is currently planning to implement GBC for its electric and gas customers by March 31, 2021. National Grid may deliver these services ahead of this date, if possible, and cost-effective to do so.
- NYSEG allowed customers to use GBC using a third party vendor as part of its Energy Smart Community (ESC) Energy Manager pilot. Customers in the ESC were temporarily able to use GBC to share energy usage data with six (6) approved third party vendors. NYSEG and RG&E's full implementation of GBC as part of their Energy Manager Web Portal is subject to the Commission's approval of the Companies' AMI proposal in their ongoing rate proceeding.[30]

3.1.3 Utility Energy Registry

On April 20, 2018, the Commission issued an Order approving the development and implementation of the Utility Energy Registry (UER).[31] The UER is an online platform developed and maintained by NYSERDA with the support of the State's investor-owned gas ad electric distribution utilities. The UER's primary purpose is to crowdsource sector-wise energy consumption data from utilities in New York's cities, towns, and villages. Municipalities can influence how communities use and produce energy through community choice aggregation (CCA), building codes, policies to promote distributed energy resource (DER) development, and through other strategies. The UER now has a reporting dashboard for analysts to report data online that will be instantly available to the public. The UER, as authorized in the UER Order, was intended to be a starting point that would require continuing Commission oversight and refinement with expected changes and evolution over time.

On December 30, 2019, NYSERDA filed a UER Status Report (Report) prepared by Climate Action Associates, LLC to report on the progress of the UER's implementation and operation, including the demand for, uses of, and benefits of UER data, as well as the need for

[30] Case 19-E-0378 et al., New York State Electric & Gas Corporation- Rates.

[31] Case 17-M-0315, In the Matter of the Utility Energy Registry, Order Adopting Utility Energy Registry, (issued April 20, 2018) (UER Order).

refinements.[32] The Commission is expected to prescribe changes to the UER's implementation and operation within the next year to optimize the online platform's value and worth.

3.1.4 REV Connect

In August 2017, NYSERDA launched REV Connect,[33] a centrally managed online portal with a team of experts who oversee its maintenance and evaluate idea submissions. The purpose of REV Connect is to facilitate productive relationships between energy innovators the Joint Utilities. REV Connect invites companies to connect with the Joint Utilities to accelerate innovative demonstration projects, technologies, and business models that advance New York's REV goals. The REV Connect team comprises a cross-section of subject matter experts whose backgrounds span the energy value chain. The principal partners behind REV Connect are NYSERDA, New York Battery and Energy Storage Technology Consortium (NY-BEST), Navigant Consulting, Inc., and Modern Grid Partners.

The REV Connect portal is meant to serve as a central channel that energy innovators can use to submit ideas that could potentially further the opportunities created by REV. A company that submits an idea through REV Connect receives streamlined evaluation, expert feedback, and, if successful, pairing with one of New York's utilities and other potential market partners.

To promote better targeting of proposed innovations, the portal provides its users with useful data and information resources that describe each utility's priority business needs, service territory, and REV-related initiatives. Opportunities for innovation are organized both by topic and by utility. The portal also provides links to detailed information about non-wires alternative (NWA) opportunities at each utility.

3.1.5 NYSERDA DER Integrated Data System

The DER Integrated Data System is a web site,[34] implemented and run by NYSERDA, which provides information on DERs installed in New York State. The DERs cataloged on the site include photovoltaic solar arrays, energy storage systems, combined heat and power (CHP) systems, fuel cells, anaerobic digesters, and controllable loads that are connected to a utility customer within an electricity distribution system. Many of those DERs received financial incentives from the State and report their performance data to NYSERDA. Utility customers who own or host DERs can include commercial, industrial, institutional, and multifamily facilities as well as single-family residences.

[32] Case 17-M-0315, supra, NYSERDA UER Status Report (filed December 30, 2019).

[33] See, https://nyrevconnect.com/.

[34] See, https://der.nyserda.ny.gov/.

The web site can be used to learn about DER technologies, explore where DER projects are located across NYS, and investigate DER performance (either individually or in user-defined groups). The site includes an interactive map of New York State that enables targeted searches of DER locations based on technology and provides single-click access to detailed information about each DER shown on the map. Performance data provided on this web site tracks daily real-world performance data from over 700 active DERs. Characteristic data is provided for DERs that have been accepted into any of the NYSERDA DER incentive programs that require performance monitoring or that have voluntarily provided information to NYSERDA. All characteristic data on the web site is downloadable in a single file (.xls format).

3.1.6 Building Energy Benchmarking

In the Accelerated Energy Efficiency Order, the Commission found that aggregated whole-building energy data is a crucial market enabling mechanism that can promote uptake of energy efficiency measures by building owners. As an example, the Accelerated EE Order cites New York City's Local Law 84, which requires New York City utilities (Con Edison and National Grid) to electronically provide aggregated metered consumption data for all-electric and gas accounts in any building. The law also requires that monthly whole-building aggregated data be uploaded through the EPA Energy Star Portfolio Manager, for qualifying size buildings.[35] In addition, the Commission noted that the Joint Utilities should plan for future New York State legislation mandating a similar framework for statewide building energy benchmarking.

The Accelerated EE Order requires the Joint Utilities to provide to a building owner, upon the owner's request, aggregated whole-building electric and gas meter data for any given building or tax lot for use in benchmarking through the Energy Star Portfolio Manager.[36] In addition, the Commission established rules to protect against the unauthorized determination of an individual building tenant's energy use, which govern the availability of the data to the building owner. The Accelerated EE Order also requires the utilities to develop the capability for the automated upload of aggregated data, and along with NYSERDA, develop a programmatic offering which utilizes benchmarking data to be marketed to decision-makers of suitable building types.[37]

As of 2019, only Con Edison and National Grid have implemented capabilities for automatically uploading monthly aggregated whole-building energy consumption data; however, this is significant in that their respective service territories contain roughly half of the multi-tenant buildings in New York State. NYSEG, RG&E, and Central Hudson have each begun the system integration needed to enable automated upload capabilities within the next two

[35] New York City Local Law 84 of 2009.

[36] Accelerated EE Order, p. 46.

[37] Id.

years. O&R and National Fuel Gas Distribution Corporation have not yet started developing automated upload capabilities but are expected to begin soon.

3.2 Assessment of Current Energy Data Resources

This section assesses New York's current portfolio of available energy data and accessible energy data resources with respect to availability, accessibility, and usefulness. The overall conclusion that can be formed from these assessments is that for most of the State's energy stakeholders, the current energy data landscape is inadequate and inefficient. Staff's proposed IEDR provides a comprehensive and coherent vision to move beyond the serious shortcomings of the current landscape and provide energy stakeholders with useful access to useful energy-related information and tools in the most efficient manner that will accelerate progress toward achieving the State's energy and climate goals.

3.2.1 Availability

Information can be made available for useful access only if it exists in the first place. Fortunately, several types of system, market, and customer information that are useful to energy stakeholders currently exist at the utilities and other organizations, in one form or another. Examples of useful information generally existing at the State's electric and gas distribution utilities include system topology, system asset data, reliability statistics, DER interconnection data, NWA procurement opportunities, distribution investment plans, distribution tariffs, bulk power market zones and values, customer classes, customer rates, customer energy consumption, customer bills, meter asset data, service configurations, and service locations. Useful information available from various non-utility sources includes demographic data, economic statistics, building characteristics, zoning, tax rules and rates, weather data, environmental data, and transportation data.

On the other hand, due to technical and/or business constraints and decisions that vary by organization, several other types of system, market, and customer information useful to the State's energy stakeholders are available only partially, if at all. Examples of inadequate information availability include: (1) no detailed consumption data for more than half of the State's electricity and natural gas consumers; (2) limited market and consumption data for other combustible fuels such as heating oil, propane, kerosene, gasoline, diesel fuel, wood pellets, and firewood; (3) little or no load and performance data for many of the distribution systems that serve the State's rural areas; (4) available hosting capacity data applies only to solar sources, lacks adequate temporal and locational granularity, is updated too slowly, and does not forecast future conditions; and (5) little or no load, performance, and forecast data for EVs and charging resources.

While many types of information are available for all parts of New York State, the scope and variety of information available at any one organization generally serves the purposes of that organization only. For example, any given utility will have only the information that applies to its respective plans, operations, and markets. Consequently, to compile a usable statewide information set, stakeholders must collect, validate, normalize, and combine information provided piecemeal from multiple organizations. This is a major obstacle for the many stakeholders who do not have enough resources to support the effort.

Relational information that identifies and characterizes the relationships between different individual information elements is a foundational resource that enables useful analyses based on those relationships. In the New York's current information environment, such information generally exists only to the extent that it serves the purposes of the organizations that maintain and use those related information elements. For example, relational information generally exists for the relationships between customer accounts and energy consumption data, between customer accounts and service points, and between service points and distribution assets. Importantly, much of the relational information existing at the various organizations is also useful to multiple stakeholder categories.

Meanwhile, other relational information that would be valued highly by many energy stakeholders does not yet exist for many types of information. In particular, relational information generally does not exist for the relationships between the information elements available from the utilities and the many useful information elements that are available from non-utility sources. For example, there is very little relational information that identifies and describes the relationships between utility customers and the various non-utility attributes of their respective service locations (i.e., demographic data, economic statistics, building characteristics, zoning category, tax district, tax rules and rates, local weather data, local environmental data, flood zoning, and transportation data). This all means that individual stakeholder organizations that would benefit from understanding the relationships among various information elements must develop and maintain useful relational information on their own – a significant challenge for most stakeholders.

3.2.2 Accessibility

To be useful to energy stakeholders, available energy-related information must be accessible. Furthermore, productive stakeholder access to that information requires means and methods for access that are practical and efficient. The current state of New York State's energy information resources described above, clearly does not provide stakeholders with practical and efficient access to the information they need.

From the stakeholders' viewpoint, the multiple pathways currently provided for information access comprise a fragmented and disjointed access framework that is hard to understand, highly impractical, and very inefficient. For many important types of information, compiling a regional or statewide data set requires a stakeholder to separately access several (up to six, or more) organization-specific data portals, each with distinct characteristics (i.e., structure, semantics, formats, procedures, functions, etc.) that the stakeholder must understand in order to access the desired information successfully.

In addition, with the utilities and other organizations each providing multiple, information-specific paths for information access, a stakeholder compiling a combined set of information comprising multiple information types must access multiple information sources, each with its own distinct characteristics, even when the information all comes from just one organization. For example, to compile a set of utility-specific information that combines and relates customer service locations with locational hosting capacity data, a stakeholder must separately access, understand, and combine at least two distinct information sources.

3.2.3 Usefulness

Staff finds that the energy information resources currently available do not readily provide the State's energy stakeholders with useful access to useful energy-related information. This lack of usefulness substantially hinders stakeholders' ability to timely develop and implement plans that advance progress towards achieving the State's REV and Climate Leadership and Community Protection Act (CLCPA) objectives.[38] The current insufficiency stems from multiple characteristics of both the information framework and the information itself.

Key information characteristics discussed in the two previous sections, availability and accessibility, are fundamental prerequisites to usefulness – information that cannot be obtained cannot be used. While an increased amount of information is already available and accessible in today's environment, the usefulness of that information is diminished because some types of information are only partially available or do not exist at all, and, because acquiring a complete set of information needed for a given purpose frequently requires accessing and using several dissimilar information sources that are separately governed and maintained by several distinct entities.

The usefulness of both the framework and the information is also materially affected by the scope and variety of functions enabled within the environment. Unfortunately, the functions enabled in the current environment lack both the scope and variety needed by the New York's energy stakeholders. This is largely due to the fragmented, decentralized, compartmented, and multi-source structure of the current framework. Generally, a function operating within any one of the many resources (filtering, for example) is limited to the scope of information available within the individual resource. To apply that same function to information acquired from multiple resources requires the stakeholder to either run the function separately in each of those resources (assuming the same function exists in each) or independently implement and apply the function after the necessary information set is acquired separately from each resource. Meanwhile, the variety of functions available in the current environment is limited to a small collection of simple, single-stage, single-use, structural operations (i.e., searching, filtering, linking, viewing, and downloading) and thus does not enable stakeholders to create, save, and run the kinds of repeatable, multi-stage, multi-

[38] 2019 N.Y. Ch. 106.

parameter, structural, logical, and mathematical operations that would efficiently generate more useful information.

Another particularly important factor affecting the usefulness of an information environment is the degree to which there is useful relational information that describes the relationships among the various information elements throughout the environment. As noted above in section 3.2.1 on Availability, there is an acute lack of integrated relational information in the current information environment, both for information within a single resource and information spanning multiple resources. This dearth of relational information seriously hampers stakeholders' ability to find, analyze, and generate useful information. For example, stakeholders cannot use the current environment to identify energy consumers who are served concurrently by two separate and unaffiliated energy suppliers.

Any one of several information attributes - granularity, precision, accuracy, age, and uniformity – can either increase or decrease the information's usefulness. To be sufficiently useful in a given use case, one or more attributes of an information element must meet or exceed a minimum level of adequacy. For example, to enable many use cases that employ time-series interval data for energy usage, the length of the time intervals (the temporal granularity) must be no greater than one hour. Daily or monthly intervals would be of little or no use. In today's environment, such temporally granular usage data is not available for a large number of utility customers due to the gradual rollout of smart metering statewide.

Similarly, some potential use cases require data that meet minimum thresholds for precision and accuracy. For example, a use case could require time data that is precise to the second and accurate to one-tenth of a second. Information that does not satisfy the precision or accuracy requirement could materially reduce the validity of use case results. To provide local grid services, a DER provider needs information about the surrounding grid that accurately describes true grid conditions. The data must also be precise enough to enable useful analyses that inform DER providers' investment and operating decisions. In today's data environment, stakeholders have almost no visibility into distribution-level system conditions, outside of periodic updates of hosting capacity maps, NWA RFPs, and the limited updates in the utilities' DSIPs.

Furthermore, each potential use case has a maximum age (or latency) for each information element used. For example, hosting capacity data for a distribution circuit could be of little or no use to a DER developer if it is more than a few months old. This can be particularly challenging in today's environment, as the DSIPs are only filed biennially, which can leave the data contained within the DSIPs quite stale. Meanwhile, the data available from other utility sources are irregularly updated at different, uncoordinated times that are often too late for the purposes of many possible use cases, further increasing the complexity of and decreasing the usefulness of stakeholder's' analyses.

Finally, the usefulness of an information environment depends greatly on the uniformity of the structures, interfaces, and information elements within that environment. The Joint Utilities have done a lot of work to increase the consistency of the data provided in their DSIPs and elsewhere. Nonetheless, in the multi-source environment currently provided by the utilities, the organization and attributes of data elements often vary significantly from one source to the next. For example, different utilities use different approaches for calculating their system capacity factors and they often change the capacity factor for a given location without disclosing their basis for making the change. This sort of inconsistency greatly increases the complexity and difficulty of stakeholders' efforts to validate and combine data for holistic analyses.

4 Notable Energy Data Initiatives in Other States

New York is one of several states that are conducting initiatives to increase the accessibility and usefulness of energy-related data available from their utilities and other sources. The following sections provide summaries of several notable data initiatives in other States that have informed Staff's recommendations.

California

The California Public Utilities Commission (CPUC) has recognized the need for accessible, higher quality, and standardized data to encourage the market for DERs. In an order issued on September 23, 2013, the CPUC authorized utilities to provide customer data to third parties when requested by the customer. This allows utilities to provide customer energy usage data to third parties in a secure way that protects both ratepayers' privacy and utilities from liability. To further protect ratepayer's privacy, it also requires that third parties be pre-approved by the utility as a trusted vendor. This allows DER providers marketing in the State to target interested consumers and tailor their offers to the specific customer by requesting their energy usage data from the customer, receive it from the utility, and then use that data to tailor their offers to the specific customer, increasing the value of potential products and maximizing the value derived from these DERs.

CPUC continued to make data access a priority and in an order issued on May 5th, 2014, the CPUC adopted rules that provided access to aggregated energy usage and other related data to local government entities, researchers, and state and federal agencies. The CPUC instructed utilities to release the total monthly sum and average of customer electricity and natural gas usage by zip code and customer class quarterly. The CPUC order also defined the process through which entities could request this data and formed the Energy Data Access Committee (EDAC) to advise the utilities on how data access could be improved, identify best practices, and mediate disputes between data requestors and the utilities. This data is vital for many research efforts, long-term system planning, and local benchmarking efforts.

CPUC was also aware that for data to be useful, it would have to be readily available in a standardized format. Consequently, the data described above is mandated to be made available in standard data formats, at least one of which must be a standard machine-readable format, like CSV or XLS. For data transfers, GBC is used as the communication standard utilities and third parties can design around. This prevents utilities from using proprietary or esoteric formats, reducing the value of the data or raising its cost through more processing or having to pay the utility to offer the data in a more accessible format.

Illinois

Like other states, Illinois has also prioritized the availability of retail usage data through GBC and usage portals to encode and transfer ratepayers' energy usage data to third parties. For this purpose, the Illinois Commerce Commission (ICC, the entity responsible for regulating public utilities in Illinois) created the Data Access and Retrieval Tenets (DART) tariff for Commonwealth Edison (ComEd). The DART tariff enables third parties' access to ComEd residential usage data. The data is in a standardized AMI interval data format and is transferred by ComEd through its Retail Electric Supplier (RES) portal and GBC. Third parties must receive prior approval from the retail customer whose data is requested, and the third party must set up and certify that its system meets the requirements to hold the data securely. All data acquired through the DART tariff is considered confidential and any use for commercial purposes not reasonably related to the conduct of the Company's business (such as the sale of data or the analysis of the data) is prohibited.

The two methods of receiving customer usage data from ComEd, the RES portal and GBC, vary in the setup required and how often information can be requested and received. Third parties do not require an extensive setup for the RES portal, and these portals are typically accessed through standard web browsers. However, requests from the RES portal are limited to once per month per customer, along with access to the previous consecutive twenty-four billing periods. This means that the RES portal is useful for DER providers that require current and historical data to tailor their offerings to customers but do not require ongoing or frequent access to their existing customers' data. Access through the GBC API is more advanced and allows access to the same historical data as the RES portal but can also be refreshed daily through the GBC API. This type of access is more useful for third parties who provide smart products and demand response resources that rely on current data.

New Hampshire

New Hampshire bill SB284, passed and effective on September 17, 2019, and supported by legislators and the New Hampshire Office of Consumer Advocacy (OCA), mandated the New Hampshire Public Utilities Commission (PUC) to open docket DE 19-197 for all New Hampshire electric and gas companies. This docket aims to address data access and privacy issues. The bill established the goal of a statewide online energy data platform to provide information about energy use to ratepayers, third parties, and investor-owned utilities (IOUs). The envisioned platform aims to provide access to granular energy data to empower consumers to actively manage their data usage and drive third party innovation. This data platform will contain aggregated data at the neighborhood, municipality, and regional levels. The legislature expects that the aggregated data will also be particularly useful for municipalities interested in introducing municipal aggregation programs.

The effort in New Hampshire is in its infancy, with the first prehearing conference held on February 3, 2020, and PUC Staff requested scoping comments on February 10, 2020. The conference was well-attended, and numerous stakeholders have provided comments, including the State's Office of Consumer Advocacy, Mission:data, the City of Lebanon, and the Joint Utilities. As a major partner in the effort, the OCA has defined six "core" use case datasets for the platform and its accompanying API, whose purpose is to enable a variety of business use cases such as access to green button connect and improved analytics for EE programs.

The six core use case datasets identified by the OCA are billing, TOU, demand study, multi-state and utility, multi-fuel, and a Statewide index, the last dataset referring to the idea that the SB284 platform will act as a single source of truth for all electricity and other fuel information in the State. These data will facilitate third party billing (for ESCOs and IOUs), the expansion of demand studies, and encourage CCA adoption by aiding municipalities in their CCA efforts. To support this broad range of use cases and future use cases that have yet to be defined, the SB284 data platform will be built with database extendibility in mind and the ability to have independent, topic-limited frontends that have varying levels of access as needed for each use case. DPS Staff is monitoring this proceeding closely to ensure that the State will be able to exchange lessons learned to encourage the adoption of these platforms in both States.

Texas

The transmission and distribution service providers (TDSPs) in Texas jointly own and operate Smart Meter Texas (SMT), a web portal and data repository that receives and stores smart meter data, going back up to seven years, for more than 7.3 million residential and small business customers. The portal enables customers to access their energy usage data for their own use and share their data with the competitive energy service providers that vie for customers in the state's deregulated energy market

Several times every day, the TDSPs collect a daily midnight register read and the previous day's recorded interval usage data from the smart meters they own. This data is transmitted from the smart meters back to the TDSPs using the TDSP meter communications networks (wired and wireless) designed for this purpose. The TDSPs store the meter usage data in their meter data management systems and perform a standard validation, editing, and estimation process on the data before preparing standard formatted files for transmittal to SMT and the Electric Reliability Council of Texas. Once the data is received and stored in the SMT, it becomes available to third parties to request. As with implementations existing or planned in other States, third parties requesting data from the SMT must first receive permission from the customers in question before any data are shared. The SMT provides a method for customers to grant third parties access to their usage data and In-Home Devices, including using the standardized GBC format.

5 The Path Ahead

As described above, the Commission has identified the need for useful access to useful energy-related data to enable achievement of the State's energy policy goals established in various Commission orders since the REV Track One Order. Based on Staff's review of the current status of those various data initiatives, there is currently a clear gap between what the Commission envisioned and what has been achieved to date. This gap was validated by the DER industry data initiative which demonstrated a market need, that if met, could unlock many useful business cases. Those market needs have become more urgent with the recent adoption of the CLCPA. The overarching impact of the CLCPA goals on various aspects of the New York economy - including electric utilities, natural gas utilities, buildings and transportation - make it imperative that the State's energy stakeholders have useful access to useful energy-related information. Staff finds that an IEDR is the least costly and most efficient way to enable such access to energy-related information acquired from the State's energy utilities (both electric and gas) and other sources.

This section describes a proposal for planning, designing, implementing, operating and maintaining the IEDR within a governance framework that ensures success through best practices. In the most general terms, the IEDR should collect, integrate, and make useful a large and diverse set of energy-related information on one statewide data platform. The types of information and tools made accessible through the IEDR should materially improve stakeholders' ability to understand and affect the provision and use of electricity and natural gas in New York State. The proposed IEDR is a sophisticated information system capable of: automatically and securely acquiring a large volume and wide variety of information from many sources; normalizing, managing and securing large amounts of diverse data; analyzing the acquired information to generate other useful information; applying advanced information controls to manage users' access to functions and data; timely performing extensive, user-defined data analyses; timely and securely exporting data to users and other systems; and, efficiently supporting rigorous system administration, security, and operating processes.

From the beginning, the IEDR's contents and capabilities should evolve in a sequence that closely aligns with use case priorities that are determined on the basis of stakeholder value, feasibility, and advancement toward the State's energy policy goals. At a minimum, the data elements initially implemented in the IEDR should comprise a data set that includes the MVDS.[39]

To advance development of a statewide IEDR, the Commission should begin with an order specifying the IEDR's purpose, scope, capabilities and establishing frameworks for funding, program management, and governance. Staff's recommendations for those aspects of the IEDR are described below.

5.1 General Recommendations for an Integrated Energy Data Resource

Staff proposes that the Commission require the design, development, and implementation of a statewide IEDR that will collect, integrate, analyze and manage a wide variety of standardized energy-related information from the State's utilities and other sources. Integrating such information in one location will enable DER providers, utilities, government agencies, and others to more readily develop valuable technical and business insights by using queries and other functions to filter, aggregate, analyze, and generate useful information. Those insights will in turn lead to faster and better policy, investment, and operational decisions that will accelerate realization of New York State's REV and CLCPA goals.

Staff finds that this recommendation for an IEDR is the best and least-cost strategy for achieving the resource capabilities and features (delineated below) needed to timely provide useful access to useful information. Furthermore, Staff concludes that perpetuating the fragmented structure and governance of the existing framework will prevent any possibility of achieving satisfactory usefulness at an affordable cost and within an acceptable timeframe. In contrast to the existing framework, the IEDR concept will provide opportunities to reduce overall ratepayer costs by: taking advantage of economies of scale; minimizing the duplication of implementation and operating costs among all entities; reducing the costs to implement and maintain satisfactory levels of accessibility, data quality and uniformity; and, minimizing the costs to plan, implement, and maintain new capabilities needed to enable use cases that emerge in the future. In addition, the IEDR will substantially reduce DER provider costs related to identifying and characterizing investment and operating opportunities that benefit DER providers, the utilities, and utility customers. The IEDR concept also provides opportunities to significantly accelerate progress by focusing attention and resources on one shared platform; minimizing the duplication of efforts among the utilities; and, greatly simplifying statewide governance and coordination of resource planning and implementation efforts.

The IEDR concept also provides opportunities to significantly accelerate progress by: focusing attention and resources on one shared platform; minimizing the duplication of efforts among the utilities; and, greatly simplifying statewide governance and coordination of resource planning and implementation efforts. For example, the IEDR would enable utilities to simplify

[39] The MVDS concept described by the DER Industry Group Report is discussed in Section 2.3 and outlined in Figure1: MVDS Data Categories and Elements.

and accelerate their obligations to provide many required DSIP information items in a timely and uniform manner that meets Commission expectations.

The centralized platform provided by the IEDR should be a trusted resource that the State's energy stakeholders can use to efficiently access and analyze the statewide grid and customer information elements that are most useful to them. Furthermore, to promote used confidence and maximize user benefits, the IEDR should be recognized as the "single source of truth" for each type of information in the system. The IEDR should also allow administrators to configure and manage multiple, distinct access control profiles for a variety of user types. For instance, the access controls for a DER provider and a government entity should differ significantly.

In addition to collecting and housing the data, the IDER should provide a collection of analytic tools that would enable users to design and run useful queries and calculations that operate across all the data types in the system. The number and functionality of those tools will increase over time to align with the various use cases that develop. In addition, to comply with the data privacy and protection framework adopted by the Commission, the users' access to the IEDR's various tools will be governed by access controls that align with the legitimate needs of each user type while also preventing unwarranted access to information that does not serve those legitimate needs.

The IEDR should also perform other functions to produce additional useful information that is derived from the information acquired from its outside sources. One such function, running as an automated background process, should compensate for the large amount of missing consumption interval data (due to the lack of widely implemented smart metering) by synthesizing estimated customer interval data based on the customer's monthly consumption and the generic load profile for the customer type. Another function, run by users on-demand, should calculate monthly bill estimates based on a customer's energy usage data and digitized tariff parameters. The IEDR should also use real and synthesized customer interval data to calculate network demand at user-specified grid locations.

The design, operation, and management of the IEDR should readily accommodate adding new information sources, information types and functions as new market and utility needs emerge. Over time, the IEDR should evolve to include useful information and functions related to weather, demographics, zoning, building attributes, land attributes, property taxes, real estate values, locations of environmental justice areas, EV registrations, EV charger types and locations, EV charger loads, localized grid load-serving capacity, DER aggregations by operator, DER aggregations by grid service, and power quality measurements.

Relational information that describes the relationships among the various information elements in the IEDR will materially affect the users' ability to find, analyze, and generate useful information. For example, with the right relational information maintained in the IEDR, stakeholders could identify energy consumers who are served concurrently by two separate and unaffiliated energy suppliers. While a lot of valuable relational information can and should be provided by the IEDR's information sources, the IEDR should also be able to continually analyze its various data sets to generate additional relational information that is not obtainable from those sources.

To ensure and maximize the usefulness of the IEDR's data elements, all information providers should fully align the attributes of each provided data element with standards for the attributes required to meet the needs of the use cases enabled by the IEDR. Important attributes that significantly affect a data element's usefulness - including temporal granularity, spatial granularity, precision, accuracy, age, and uniformity – should all meet or exceed minimum levels of adequacy for each use case that employs that data element.

As part of this proceeding, the Commission should establish a comprehensive Data Access Framework to govern the means and methods for accessing and protecting all types of energy-related information.[40] The Data Access Framework is expected to include policies that specify the approaches and criteria for determining whether any given actor is trustworthy and has a legitimate reason for accessing and using any given type of data. Policies within the Data Access Framework are also expected to stipulate when and how to implement constraints that minimize threats to confidentiality and security. All aspects of implementing and operating the IEDR must comply with the policies comprising the Data Access Framework.

To more fully explain the dimensions of the proposed IEDR program, Staff describes in detail below, the principal components of the program lifecycle including regulatory actions, program oversight, program sponsorship, program management, solution architecture, detailed design, implementation, and ongoing operation.

5.2 Regulatory Actions

The Commission should recognize the need for tasks and investments to be completed by each utility company to enable their business and operating systems to gather and transmit data to the IEDR, as well as to support the IEDR's design, development, and implementation.

Given the potential impact of the IEDR on the achievement of New York State's energy policies, Staff recommends that NYSERDA be appointed as the "Program Sponsor." The Program Sponsor should obtain and administer the funding required to carry out the steps described below. Funding should be provided from all jurisdictional electric and gas ratepayers. This includes the initial funding needed to implement the IEDR as well as ongoing funding for operating and enhancing the IEDR. Staff anticipates that the Long Island Power Authority (LIPA) and the New York Power Authority (NYPA), will engage in the IEDR development and implementation process. This will allow LIPA and NYPA to align the various energy-related

[40] Consistent with the Commission's directive in the Instituting Order, the whitepaper regarding development of a data access policy framework contains Staff's recommendations relating to this policy framework.

data activities under their control with the statewide IEDR ultimately directed by the Commission. At a minimum, LIPA and NYPA should consider the development of systems and processes that would enable their respective input to the MVDS to be provided to the IEDR to maximize benefits of the resource to New York State.

Staff is currently working with NYSERDA to issue a Request for Information (RFI) to obtain the information needed to inform the Commission on the expected expenditures necessary to build and operate the IEDR. The Commission should use such information, as well as information obtained through the comment process on this whitepaper, to set an overall budget cap to be managed by the Program Sponsor and to understand the sequence and timing of work and expenditures by all program participants. The Program Manager should be required to submit to the Program Sponsor detailed budgets and schedules for each aspect of building the IEDR. The Program Manager and Program Sponsor should administer competitive procurements to achieve the most efficient design, build and operation of the platform. The procurement decisions made at various points in the program lifecycle should consider inputs from the utilities and other stakeholders, with final selection being the responsibility of the Program Sponsor and DPS Staff.

To address the efforts and tasks that each utility will need to carry out, Staff seeks comment from the utilities on the ability of their respective systems and processes, as they exist today, to provide to the IEDR the data items listed in Appendix B (which includes the elements comprising the MVDS). Those comments should include descriptions and best cost estimates of the required changes that would enable the utilities to fully provide the recommended data elements to the IEDR. Each utility should also describe and quantify its currently planned investments and operating expenses that the proposed IEDR could reduce or eliminate (for instance, costs associated with Green Button Connect and the Utility Energy Registry). The Commission can use all this information to formulate and implement the appropriate processes for submitting, reviewing, and recovering the costs of those necessary efforts and investments. From the outset and over time, the utilities' respective IEDR-related investments should be planned and closely coordinated to achieve the schedule to design, build, and operate the proposed IEDR.

5.3 Program Oversight

The launch and progress of the proposed IEDR program should be overseen by well-qualified persons who are tasked with effectively and timely monitoring program execution and providing guidance to the Program Sponsor and Program Manager as needed to help ensure program success. As described below, these people should be organized into two groups, a "Steering Committee" and an "Advisory Group."

5.3.1 Steering Committee

The Program Sponsor should convene and work with a Steering Committee, comprising five members of DPS Staff and four members of NYSERDA staff, to timely review and when necessary act on: program issues that require Steering Committee awareness and possible actions or decisions; significant program risks that require management and mitigation; planned and unplanned deviations from the program scope, schedule, or budget; and, upcoming program milestones – especially those that depend on Steering Committee actions or decisions. The Steering Committee should also timely review all Advisory Group inputs and ensure that those inputs are appropriately incorporated into the program's various workstreams.

The Steering Committee should begin by meeting every month, with remote participation enabled by a virtual meeting technology such as WebEx or Microsoft Teams. As the program matures and stabilizes, the frequency of Steering Committee meetings could decrease to bi-monthly and then to quarterly. Steering Committee members should participate personally - substitutions or proxies should be prohibited. The Steering Committee should continue performing its functions over the life of the IEDR.

5.3.2 Advisory Group

The Program Sponsor should convene and work with an Advisory Group to enable stakeholder groups to timely provide informed commentary and guidance to the Steering Committee. Advisory Group members should be selected by the Steering Committee and should represent all relevant stakeholder groups including, but not limited to, DER developers, utilities, energy consumers, state and local government entities, and interested industry associations. The number of Advisory Group members should ensure adequate representation across stakeholder groups while remaining manageable.

The scope of Advisory Group activities should include timely reviews and guidance related to: IEDR use cases and their respective requirements; priorities and schedules for enabling use cases; planned IEDR capabilities; required stakeholder capabilities; user interfaces and experience; IEDR development and testing; program governance; and upcoming program milestones – especially those that depend on Advisory Group guidance. In addition, Advisory Group members should act as testers whenever user acceptance testing (UAT) is performed. Furthermore, appropriate Advisory Group members should be included as participants in any IEDR stakeholder surveys, focus groups, feedback sessions, or workshops.

The Advisory Group should begin by meeting every month, with remote participation enabled by a virtual meeting technology such as WebEx or Microsoft Teams. The Advisory Group's meetings should be scheduled to occur midway between the Steering Committee's scheduled meetings to ensure enough time for transfers of information to and from the Steering Committee. Advisory Group members should participate personally - substitutions or proxies should be prohibited. As the program matures and stabilizes, the frequency of Advisory Group meetings could decrease to bi-monthly and then to quarterly. The Advisory Group should continue performing its functions over the life of the IEDR.

5.4 Program Sponsor

The Program Sponsor is the person or group within New York State government that is assigned responsibility for defining, initiating, overseeing, and facilitating the IEDR Program on behalf of the State. As noted above, Staff recommends that NYSERDA be appointed as the Program Sponsor. The Program Sponsor's principal duties include:

(1) creating the Program Charter (containing the Program's purpose, scope, guiding principles, objectives, participants, roles, and responsibilities);
(2) convening and working with the IEDR program Steering Committee;
(3) convening and working with the IEDR program Advisory Group;
(4) specifying, procuring, and administering the services provided by a professional Program Manager;
(5) providing the means and methods for expending the Commission-directed funding related to the program;
(6) monitoring adherence to the Program Charter by all program participants; and,
(7) helping the Program Manager investigate and resolve issues that could negatively affect the program's costs, schedule, or benefits.

5.5 Program Manager

The Program Manager is the entity responsible for organizing and administering IEDR implementation. Program management services specified by the Program Sponsor and performed by the Program Manager should include the following functions:

5.5.1 Advisory Group Engagement & Communication

The Program Manager should develop, implement, facilitate, and document a rigorous Advisory Group engagement and communication process to inform and guide all phases of the program lifecycle.

5.5.2 Develop and Manage the Program Schedule

Effective oversight of the program's progress will require development and timely maintenance of a comprehensive schedule that:

(1) identifies all significant activities related to planning, designing, building, testing, and commissioning the IEDR;
(2) describes the dependencies among those activities;
(3) establishes the planned timing of each activity;
(4) specifies the entity responsible for performing the activity; and,
(5) quantifies the resource(s) needed for the activity.

5.5.3 Develop and Manage the Program Budget

The Program Budget should encompass all Commission-directed expenditures related to planning, designing, building, administering, and operating the IEDR. Following approval of the

Initial Program Schedule, the Program Manager, working with the Program Sponsor and other entities as needed, should develop an Initial Program Budget that describes the type, purpose, predicted timing, and estimated amount of all significant expenditures.

As the program progresses, the range, scale, and timing of program expenditures will come into better focus; consequently, the Program Manager and Program Sponsor should regularly meet to review actual and predicted program expenditures and to determine whether budget and / or scope modifications are needed.

5.5.4 Procure and Manage Professional Services

The Program Manager should be responsible for developing and executing the strategy for procuring and managing all professional services needed to build and operate the IEDR. Guiding principles for the procurement strategy include obtaining best overall value for New York State and involved stakeholders, with an eye toward accelerating implementation timelines, reducing initiative cost & risk, and protecting robustness of agreed-upon scope through partnering with high-quality service providers that have values aligned with those of New York State.

The Program Manager should identify opportunities for obtaining economies of scale and/or scope from any contracting required to obtain needed professional services, in order to afford the team decision-making flexibility that enables best possible procurement execution. The bucketing of the work to be done that is described in this whitepaper (by function and general timing) does not necessarily mean that each functional need or project phase or service provider will be a different entity or contracted for separately.

Successful IEDR implementation will depend on professional services that enable:

(1) development of the IEDR architecture;
(2) development and integration of detailed designs and specifications;
(3) deployment and integration of components and services;
(4) testing and commissioning the IEDR's capabilities;
(5) system administration; and,
(6) system operations.

5.5.5 Procure IEDR Components

The Program Manager should be responsible for timely procuring and distributing all equipment, software, materials, facilities, network services, platform services, and other elements needed to fully implement the IEDR core.

Guiding principles for the IEDR's component procurement strategy include obtaining best overall value for New York State and involved stakeholders, with an eye toward accelerating implementation timelines, reducing initiative cost & risk, and protecting robustness of agreed-upon scope through sourcing high-quality components to be deployed during the IEDR implementation.

The Program Manager should identify opportunities for obtaining economies of scale and/or scope from any contracting required to obtain needed IEDR components, in order to afford the team decision-making flexibility that enables best possible procurement execution. The bucketing of the work to be done that is described in this whitepaper (by function and general timing) does not necessarily mean that the IEDR components needed for each functional need or project phase or service provider will be contracted for separately or from different entities.

Procuring the elements that are not part of the IEDR core environment - mostly being the utility-specific elements that are separately deployed, operated, and maintained by the participating utilities – should be the responsibility of the utilities and other program participants.

5.5.6 Coordinate Work Performed by Program Contributors

The Program Manager should act as the primary coordinator of work performed by program contributors to plan, design, deploy, test, commission, and operate the IEDR elements that are not part of the core IEDR environment.

5.5.7 Manage Program Risks

By applying best practices for managing program risks, the Program Manager should organize and conduct the activities needed to facilitate timely anticipation and mitigation of risks that could hinder or prevent successful IEDR implementation.

5.5.8 Program Reporting

The Program Manager should implement and maintain a program reporting framework that includes: (1) monthly production and publication of reports that address all aspects of the IEDR program; (2) ongoing maintenance of a program dashboard that presents an at-a-glance summary of program status; and, (3) frequent briefings to the Program Sponsor, Steering Committee, and Advisory Group. Program reports should, in the context of the program schedule and budget, describe and explain (where necessary) the program's accomplishments and expenditures to date, current work and expenditures in progress, the latest program risk assessment and mitigation plan, and upcoming work and expenditures.

5.6 Solution Architecture

The IEDR Solution Architecture will provide the information needed to fully specify the requirements for a complete IEDR Design. To ensure realization of the IEDR's potential value, the Solution Architect should employ an approach structured around identifying, understanding, and prioritizing potential IEDR use cases.

Details for such an approach are described below in Sections 5.6.1 – 5.6.7. In addition, the Solution Architect must rigorously identify and comply with all applicable requirements concerning confidentiality and system security, as established in the *Data Access Framework for Strategic Use of Energy-Related Data*.

5.6.1 Stakeholder Engagement

Working within the Advisory Group engagement process implemented and managed by the Program Manager, the Solution Architect should obtain inputs on: (1) possible IEDR use cases from all potential user categories; and, (2) technical and business considerations from utilities, third party data providers, platform developers/integrators, and prospective IEDR users.

5.6.2 Identify and Characterize Beneficial IEDR Use Cases

A use case would be particularly beneficial if it can materially improve or accelerate investment, operational, and/or regulatory decisions related to DERs, energy efficiency, environmental justice, and/or electrification strategies for transportation and buildings, thereby facilitating faster fulfillment of one or more of New York State's REV and CLCPA objectives.

The Solution Architect should identify and characterize the beneficial use cases that can be enabled or enhanced by the capabilities of a suitably designed IEDR. In doing so, consideration should be given to the needs and interests of multiple user categories including (but not limited to):

- DER developers;
- DER operators;
- electric and gas utilities;
- electric and gas customers;
- EV suppliers;
- EV owners/operators;
- developers and operators of EV charging infrastructure;
- developers and suppliers of building electrification solutions;
- developers and suppliers of energy efficiency solutions;
- municipal and county governments; and,
- various New York State government agencies and authorities (NYSERDA, DPS, Department of Environmental Conservation, Department of Transportation, NYPA, LIPA, etc.).

The use cases considered by the Solution Architect should include (but not be limited to):

- Use Cases Supporting Development and Use of DERs:
  - identifying, evaluating, and selecting potential DER locations;

- identifying, evaluating, and engaging potential DER customers;
- preparing and optimizing DER development plans;
- preparing and optimizing DER operating plans;
- designing, implementing, and operating DER aggregations;
- monitoring and evaluating the deployment and use of DERs; and,
- designing and implementing Community Distributed Generation (CDG) solutions.

- Use Cases Supporting Transportation Electrification:
  - identifying, evaluating, and engaging existing EV owners/operators;
  - identifying, evaluating, and engaging potential EV owners/operators;
  - monitoring and evaluating EV acquisitions and uses;
  - identifying, evaluating, and selecting potential locations for EV charging facilities;
  - preparing and optimizing plans for developing EV charging facilities;
  - preparing and optimizing plans for operating EV charging facilities; and,
  - monitoring and evaluating the deployment and use of EV charging facilities.

- Use Cases Supporting Building Electrification:
  - identifying, evaluating, and engaging energy consumers and energy managers in existing buildings;
  - identifying, evaluating, and engaging energy consumers and energy managers in planned buildings;
  - monitoring and evaluating acquisitions and uses of building electrification solutions;
  - building energy benchmarking;
  - identifying, evaluating, and selecting opportunities for building electrification;
  - preparing and optimizing plans for developing building electrification solutions;
  - preparing and optimizing plans for operating building electrification solutions; and,
  - monitoring and evaluating the deployment and performance of building electrification solutions.

- Use Cases Supporting Energy Efficiency (EE):
  - identifying, evaluating, and engaging customers with existing EE solutions;
  - identifying, evaluating, and engaging potential EE customers;

- monitoring and evaluating EE acquisitions and uses;
- building energy benchmarking;
- identifying, evaluating, and selecting EE opportunities;
- preparing and optimizing plans for deploying EE solutions;
- monitoring and evaluating the deployment and use of EE solutions; and,
- designing and implementing Community Choice Aggregation (CCA) solutions.

- Use Cases Supporting Utility Functions (Electric and Gas):
  - system planning;
  - DER interconnection;
  - system operations;
  - market enablement;
  - market operations;
  - customer programs and services; and,
  - regulatory/statutory compliance.

- Use Cases Supporting Local Government Functions:
  - building energy benchmarking;
  - Community Choice Aggregation;
  - Community Distributed Generation;
  - facility siting and permitting;
  - environmental justice initiatives;
  - economic development; and,
  - planning and zoning.

- Use Cases Supporting State Government Functions:
  - energy-related R&D;
  - regulatory research and planning;
  - regulatory oversight;
  - building energy benchmarking;
  - facility siting and permitting;
  - environmental justice initiatives; and,
  - economic development.

5.6.3 Identify and Characterize Use Case Requirements

For each beneficial use case, the Solution Architect should identify and characterize the IEDR functions, data source(s), data types, data attributes, data relationships, data access controls, system components, system attributes, system interfaces, technical processes, business processes, and people needed to enable the use case. Moreover, in addition to describing the system requirements, the Solution Architect should identify and characterize the policy, regulatory, statutory, and governance conditions needed to enable the use case.

5.6.4 Develop Preliminary Use Case Solutions

Based on the use case requirements, the Solution Architect, assisted by other entities as needed, should develop a preliminary use case solution for each use case. The preliminary use case solution should include: (1) a profile that describes the use case characteristics and requirements; and, (2) text, tables, and diagrams that present a preliminary use case design that is detailed enough to inform the use case feasibility and prioritization assessments that will follow (see sections 5.6.5 and 5.6.6).

Each preliminary use case solution should identify, describe, and explain the need for each of the following solution elements:

Functions

The types of functions described for any given use case could include (but not be limited to): data acquisition; data management; data normalization; data grooming; database queries; data generation; cybersecurity; user-controlled functions; operator-controlled functions; data presentment; and, data exports. The description of each function should indicate whether the function is unique to the use case or is shared by other use cases.

Resources

The types of resources described for any given use case could include equipment, software, facilities, network links, system services, datasets, and people. The description of each resource should indicate whether the resource is unique to the use case or is shared by other use cases.

Policies

It is possible that enabling a use case would require one or more policy conditions that don't currently exist at the state and/or local level. For example, necessary policy conditions could involve practices, rights and/or obligations affecting data sourcing, data access controls, data management methods, and consumer protection. In some cases, a needed policy condition would require modification of an existing regulation or law; in other cases, it might be necessary to create a new regulation or law. The description of each policy requirement should indicate whether the requirement is unique to the use case or is shared by other use cases.

Roles and Responsibilities

Every IEDR use case will require a framework of roles and responsibilities spanning multiple people and organizations. The roles and responsibilities involved in a use case would include, for example, the end-users, the data provider(s), the data manager, the access administrator, the system operator, and functional process administrator(s). In some cases, a role and its respective responsibilities could readily fit within the functions/capacities of an existing organization and/or person(s). In other cases, it might be necessary to either modify the functions/capacities of an existing entity or create a new entity. The description of each role connected to the use case should indicate whether the role is unique to the use case or is shared by other use cases.

Use Case Costs

Implementing and sustaining an IEDR use case will incur capital and/or operating costs for each of the solution elements described above. The description of each cost should indicate whether the cost is unique to the use case or is shared with other use cases. Costs should be an important factor considered in the assessment of use cases and their respective solutions. In addition, to the extent that it is possible and practical, the timing of each use case cost should be predicted relative to the beginning of use case implementation.

5.6.5 Assess Use Case Feasibility

Based on the preliminary use case solutions, the Solution Architect and Program Manager should jointly evaluate the feasibility of each use case. Factors affecting the feasibility assessments should include each of the solution design elements described in the previous section (functions, resources, policies, roles and responsibilities, and funding). Then, each use case should be assigned to one of the following categories of feasibility:

- feasible and readily implemented;
- feasible following resolution of any minor technical/business/policy constraints;
- feasible following resolution of any technical/business/policy constraints that are significant but solvable; and,
- not feasible due to significant technical/business/policy constraints that are not solvable.

5.6.6 Prioritize the Feasible Use Cases

Based on the preliminary use case solutions and feasibility assessments discussed above, the Solution Architect, Program Manager, and Program Sponsor should jointly determine the appropriate priority level for each feasible use case. The prioritization process should consider and compare: (1) the benefits derived; (2) the resource and process requirements; (3) the policy, regulatory, statutory, and governance requirements; (4) the relationship between time and feasibility; and, (5) the estimated costs to design, deploy, and operate the supporting resources and processes.

5.6.7 Develop the IEDR Solution Architecture

Guided by the Program Manager and Advisory Group as needed, and in accordance with the schedule and work-product requirements specified in the Solution Architecture Contract, the Solution Architect should develop and recommend an IEDR Solution Architecture that will facilitate timely and efficient design, deployment, and operation of each planned IEDR use case. All aspects of the recommended Solution Architecture should be detailed enough to enable subsequent development of a complete IEDR Design. Acceptance of the recommended Solution Architecture should be subject to review and approval by the Program Manager and Program Sponsor.

5.7 IEDR Design

The IEDR design will provide the information needed to fully implement the IEDR. With assistance provided by the Solution Architect as needed, the Program Manager should: (1) specify the professional services needed to develop a comprehensive IEDR design; (2) identify several organizations that are well qualified to provide those design services; (3) solicit and evaluate competitive proposals from those organizations; (4) select the preferred service provider; (5) negotiate and sign a contract that is mutually acceptable to the Program Sponsor, the Program Manager, and the selected Design Contractor; (6) oversee the Design Contractor's performance for the duration of the engagement; and, (7) administer the budgeting, reporting, payment, change control, and risk management processes related to the Design Contractor's services.

5.7.1 Prepare a Preliminary Design Plan

Before developing the detailed IEDR design requirements, the Solution Architect should prepare a Preliminary Design Plan that describes the elements, structure, timing, deliverables, and estimated cost of the design effort.

5.7.2 Specify Required Design Services

Following approval of the Preliminary Design Plan, the Solution Architect, assisted by other entities as needed, should specify the detailed requirements for fully designing the IEDR. The complete IEDR design will comprise descriptive text, specifications, tables, diagrams, configuration parameters, data definitions, data schemas, computer code, operating procedures, and other work products that describe and explain all aspects of the IEDR's composition, configuration, and operation. The scope of the complete design should encompass the IEDR and all the other entities (systems and people) that will interact with the IEDR. The finished design should provide all the information needed to specify, procure, and execute all necessary IEDR implementation services. The Program Manager should procure the necessary design services based on the requirements specified.

5.7.3 Design Schedule

Effective tracking and management of the design effort will require development and timely maintenance of a schedule that identifies the planned design activities, describes the dependencies among those activities, and establishes the planned timing of each activity. The sequence and timing of the design activities should result in delivery of design work products that will enable a timely, priority-driven, multi-phase IEDR implementation. To help inform the Program Manager's procurement decision, each prospective Design Contractor's proposal should include a preliminary design schedule.

5.7.4 Advisory Group Engagement

Working within the Advisory Group engagement process managed by the Program Manager, the Design Contractor should employ technical conferences and other methods as needed to obtain design-related inputs from utilities, third party data providers, platform developers/integrators, and prospective IEDR users.

5.7.5 Develop the Complete IEDR Design

The Design Contractor - with guidance from the Program Manager, Solution Architect, and Advisory Group as needed - should develop the complete IEDR design in accordance with the Design Schedule and the design requirements specified in the Design Contract. All aspects of the IEDR design should comply with the approved Solution Architecture and should be detailed enough to fully enable acquisition, deployment, testing, and operation of all IEDR elements.

5.8 IEDR Implementation

IEDR implementation comprises full deployment, integration, and activation of all elements needed to fully implement the IEDR. With assistance provided by the Solution Architect and Design Contractor as needed, the Program Manager should: (1) specify the professional implementation services needed to fully implement the comprehensive IEDR design; (2) identify several organizations that are well qualified to provide those implementation services; (3) solicit and evaluate competitive proposals from those organizations; (4) select the preferred Implementation Contractor; (5) negotiate and sign a contract that is mutually acceptable to the Program Sponsor, the Program Manager, and the selected Implementation Contractor; (6) oversee the Implementation Contractor's performance for the duration of the implementation; and, (7) administer the budgeting, reporting, payment, change control, and risk management processes related to the Implementation Contractor's services.

5.8.1 Prepare a Preliminary Implementation Plan

Before developing the detailed IEDR implementation requirements, the Solution Architect, assisted by the Design Contractor as needed, should prepare a Preliminary

Implementation Plan that describes the elements, structure, timing, deliverables, and estimated cost of the implementation effort.

5.8.2 Specify Required Implementation Services

Following approval of the Preliminary Implementation Plan, the Solution Architect, assisted by the Design Contractor and other entities as needed, should specify the detailed requirements for fully implementing the IEDR.

5.8.3 Implementation Schedule

Effective tracking and management of the implementation effort will require development and timely maintenance of a schedule that identifies the planned implementation activities, describes the dependencies among those activities, and establishes the planned timing of each activity.

To help inform the Program Manager's procurement decision, each prospective Implementation Contractor's proposal should include a preliminary implementation schedule. The selected Implementation Contractor and the Program Manager - assisted by the Solution Architect, Design Contractor, and System Operator as needed - should then finalize and agree to a mutually acceptable implementation schedule during contract negotiations.

5.8.4 Advisory Group Engagement

Working within the Advisory Group engagement process managed by the Program Manager, the Implementation Contractor should obtain implementation-related inputs from the utilities, third party data sources, providers of system components and services, and the System Operator.

5.8.5 Build and Activate the IEDR

The Implementation Contractor - with guidance and assistance provided as needed by the Program Manager, Solution Architect, Design Contractor, and System Operator - should acquire, deploy, test, and commission all IEDR elements as designed and in accordance with the Implementation Schedule.

5.9 IEDR Operation

IEDR operation comprises all the planning, scheduling, system administration, process control, monitoring, maintenance, access control, problem detection/resolution, change management, user support, and reporting activities needed to effectively manage the functionality and performance of operational IEDR capabilities. With assistance provided by the Solution Architect and Design Contractor as needed, the Program Manager should: (1) specify the operating services needed to fully manage ongoing IEDR functionality and performance; (2) identify several organizations that are well qualified to provide those operating services; (3) solicit and evaluate competitive proposals from those organizations; (4) select the preferred System Operator; (5) negotiate and sign a contract that is mutually acceptable to the Program

Sponsor, the Program Manager, and the selected System Operator; (6) oversee the System Operator's performance for the duration of the contract; and, (7) administer the budgeting, reporting, payment, change control, and risk management processes related to the System Operator's services.

5.9.1 Prepare a Preliminary Operating Plan

Before developing the detailed IEDR operating requirements, the Solution Architect and Design Contractor should jointly prepare a Preliminary Operating Plan that describes the elements, structure, timing, deliverables, and estimated cost of anticipated operating services.

5.9.2 Specify Required Operations Services

The System Operator should be responsible for: (1) performing the processes needed to fully operate the IEDR; and, (2) coordinating the IEDR's interactions with processes running in other systems that interact with the IEDR. Also, before any IEDR capability is commissioned for use, the System Operator should be responsible for developing, performing, and documenting the results of acceptance tests of each related IEDR operating function.

Following approval of the Preliminary Operating Plan, the Solution Architect, assisted by the Design Contractor and other entities as needed, should specify the detailed requirements for operating the IEDR.

5.9.3 Operations Schedule

Tracking and managing IEDR operations effectively will require a schedule that identifies and integrates the planned operating activities of all supporting entities, describes the dependencies among those activities, and establishes the planned timing of each activity.

To help inform the Program Manager's procurement decision, each prospective System Operator's proposal should include a preliminary operations schedule.

Once IEDR implementation begins, the Program Manager, Solution Architect, Design Contractor, Implementation Contractor, and System Operator (the Program Team) should meet periodically to assess the System Operator's progress in: (1) developing detailed IEDR operating plans; (2) preparing detailed plans for testing IEDR operating functions; (3) assembling the resources needed for running IEDR operations; and, (4) testing IEDR operating functions.

5.9.4 Advisory Group Engagement

Working within the Advisory Group engagement process managed by the Program Manager, the System Operator should obtain operations-related inputs from the utilities, third party data sources, providers of system services, and IEDR users.

5.9.5 Operate the IEDR

IEDR operations should commence and evolve as the Implementation Contractor releases IEDR capabilities to the System Operator for testing, commissioning, management, and support. Once an IEDR capability is activated, the System Operator should perform all the operating functions needed to achieve the functionality and performance specified for that capability. Operating functions performed by the System Operator should include (but not be limited to) planning, scheduling, system administration, process control, performance monitoring, system maintenance, access control, problem detection, problem resolution, change management, user support, and reporting.

Once IEDR operations begin, the Steering Committee and Advisory Group should periodically assess the System Operator's performance for each of the operating functions identified above and act as needed when performance falls short of expectations.

6 Summary

The need to provide useful access to useful energy data to enable achievement of the State's energy policy goals is apparent. The timing to provide such access has become urgent with the recent adoption of the CLCPA. Evolving the existing fragmented framework will not meet the needs of New York State's energy industry stakeholders in the most efficient and effective manner. Staff's proposal for an IEDR, and associated development, build and implementation process, will meet those needs efficiently and effectively by taking advantage of economies of scale; minimizing the duplication of implementation and operating costs; reducing the costs to implement and maintain data quality and uniformity; and, effectively planning, implementing, and maintaining new capabilities needed to enable use cases that emerge in the future. Staff recognizes the complexities involved in IEDR development. While Staff does not propose a specific timeline for IEDR readiness, Staff's intent is to be as expeditious as possible, while at the same time remaining flexible in order to take best advantage of new information during the development process, including information gained from comments and from the NYSERDA RFI. Staff will file this whitepaper for public comment, and requests that stakeholder comments follow the organizational structure of this whitepaper in order to facilitate the analysis of issues presented in each section.

Appendix A: Currently Available Online Utility Information Resources

Web links to all of the online utility information sources are publicly accessible via the System Data page of the JU web site (https://jointutilitiesofny.org/system-data/). A consolidated inventory of those links is provided below.

Contents

Distributed System Implementation Plans

On June 30, 2016 each utility filed its Initial Distributed System Implementation Plan (DSIP) under the REV Proceeding, and the Joint Utilities of New York (JU) filed a Supplemental DSIP on November 1, 2016. Each utility filed its first biennial DSIP update on July 31, 2018. The utilities are required to file their second DSIP updates by no later than June 30, 2020. The 2018 DSIP updates and the 2016 Supplemental DSIP can be accessed in PDF format via the links below.

Central Hudson Gas and Electric

Main Document

http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bA3E2E565-871B-4651-966B-127DF1325283%7d

Appendices

http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bA4B04F0C-8642-45C2-88CF-BCD9F3F1ACF2%7d

Consolidated Edison

Complete Document
http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bDE23C0BF-CF5C-4D31-BF9A-E9AC36FD659B%7d

National Grid

Complete Document
http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b1007E9DC-166C-4EF9-9B85-B55F4FA2EFB1%7d

NYSEG and RG&E

Main Document
http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b6D4F931F-B10D-438F-8288-2A77DBEDD364%7d

Appendix A: Guidance Requirements
http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bF4D348AB-6EDB-4B24-B050-1ABF84142DBE%7d

Orange & Rockland

Complete Document
http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bADD94704-5754-41A6-9CB9-3D35D589A294%7d

Joint Utilities' Supplemental DSIP:

Complete Document

https://jointutilitiesofny.org/wp-content/uploads/2016/10/3A80BFC9-CBD4-4DFD-AE62-831271013816.pdf

Capital Investment Plans

The utilities' respective Five-Year Capital Investment Plans are filed with the DPS and posted on the DPS public web site under various DPS Proceedings. Copies of the utilities' most recently filed plans can be downloaded in PDF format from the following links:

Central Hudson Gas & Electric

2020-2024 Corporate Capital Forecast, filed July 1, 2019 under Case #:17-E-0459/17-G-0460:
http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b5013C4CA-FB03-4EA1-B48C-048ED88FAF1F%7d

Con Edison

2017-2021 Capital Investment Plan filed under Case 113-E-0030:

https://jointutilitiesofny.org/wp-content/uploads/2017/05/JU-Website-Con-Edison-Report-on-2016-Capital-Expenditures-and-2017-2021-Electrical-Capital-Forecast-1.pdf

National Grid

2018-2022 Capital Investment Plan filed under Case 12-E-0201:

https://jointutilitiesofny.org/wp-content/uploads/2017/05/JU-Website-National-Grid-TD-CIP-Case-12-E-0101-01312017.pdf

NYSEG/RG&E

Capital Investment Plan filed under Case 07-M-0906 can be found at the following link provided by the Joint Utilities of New York web site:
http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b958AC6D3-CB0F-450A-BD4F-19F1FEA87A93%7d

Orange & Rockland

2018-2022 Capital Investment Plan filed under Case 18-E-0067:
http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b393DE155-035C-4584-9F5B-C1AA6A78D667%7d

Planned Resiliency and Reliability Projects

The utilities' most recently published plans for resiliency and reliability projects are described in their latest reliability reports filed with the New York Public Service Commission.

Central Hudson Gas & Electric

2017 Annual Reliability Report filed March 29, 2018 under Case 18-E-0153:
http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bB533CC02-6F9A-4033-8048-A0DDEBB29DBC%7d

Con Edison

2016 Annual Report on Electric Service and Power Quality filed March 31, 2016 under Case 18-E-0153:

https://jointutilitiesofny.org/wp-content/uploads/2017/06/JU-Website-2015-Annual-Report-on-Electric-Service-and-Power-Quality-Con-Edison.pdf

National Grid

2017 Annual Electric Reliability Report filed March 29, 2018 under Case 18-E-0153:

http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b7B0CED6F-B37A-4E49-BC3E-0827D636FFE4%7d

NYSEG/RG&E

2017 Annual Reliability Report filed March 31, 2016 under Case 18-E-0153:

http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b2C1D818E-074B-4ED3-B643-CF8A989CCD6F%7d

Orange & Rockland

Service Reliability Report for 2017 System Performance filed April 13, 2018 under Case 18-E-0153:

http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b6DB7740F-6B4D-43CF-BAF1-D40128A9D5F6%7d

Reliability Statistics

The utilities' most recently published reliability statistics are described in their latest reliability reports filed with the New York Public Service Commission.

Central Hudson Gas & Electric

2017 Annual Reliability Report filed March 29, 2018 under Case 18-E-0153:
http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bB533CC02-6F9A-4033-8048-A0DDEBB29DBC%7d

Con Edison

2016 Annual Report on Electric Service and Power Quality filed March 31, 2016 under Case 18-E-0153:

https://jointutilitiesofny.org/wp-content/uploads/2017/06/JU-Website-2015-Annual-Report-on-Electric-Service-and-Power-Quality-Con-Edison.pdf

National Grid

2017 Annual Electric Reliability Report filed March 29, 2018 under Case 18-E-0153:

http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b7B0CED6F-B37A-4E49-BC3E-0827D636FFE4%7d

NYSEG/RG&E

2017 Annual Reliability Report filed March 31, 2016 under Case 18-E-0153:

http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b2C1D818E-074B-4ED3-B643-CF8A989CCD6F%7d

Orange & Rockland

Service Reliability Report for 2017 System Performance filed April 13, 2018 under Case 18-E-0153:

http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b6DB7740F-6B4D-43CF-BAF1-D40128A9D5F6%7d

Hosting Capacity

The Joint Utilities, with guidance from stakeholders in the 2016 engagement group discussions, developed a four-stage Hosting Capacity implementation roadmap. The most recent release, Stage 3, of the Hosting Capacity displays now includes sub-feeder level analyses of large-scale solar PV systems interconnecting to distribution circuits. Each circuit's hosting capacity is determined by evaluating the potential for power system criteria violations as a result of large PV solar systems interconnecting to three phase distribution lines with an AC nameplate rating greater than or equal to 300 kW interconnecting to three phase distribution lines. More information on the analysis criteria, assumptions, FAQs and relevant background can be found in the Joint Utilities of New York web site at:

https://jointutilitiesofny.org/wp-content/uploads/2020/03/JU-DRAFT-Stage-3.0-Reference-Materials-2020-02-26.pdf

Central Hudson Gas & Electric

https://www.cenhud.com/my-energy/distributed-generation/

Con Edison

https://www.coned.com/en/business-partners/hosting-capacity

National Grid

https://ngrid.portal.esri.com/portal/home/signin.html?returnUrl=https%3A//ngrid.portal.esri.com/SystemDataPortal/NY/index.html

NYSEG and RG&E

http://iusamsda.maps.arcgis.com/apps/webappviewer/index.html?id=2f29c88b9ab34a1ea25e07ac59b6ec56

Orange & Rockland

Accessible with an O&R account or ARCGIS account

https://www.oru.com/en/business-partners/hosting-capacity

Beneficial Locations

Each utility's beneficial locations, where there may be a capacity benefit on the distribution system from distributed energy resources, are described either on their respective web sites or in their Initial Distributed System Implementation Plans (DSIPs) filed with the New York PSC on June 30, 2016.

Central Hudson Gas & Electric

Provided in the Solar Energy and Distributed Generation page of their web site:

Granularity: Circuit, Substation, Transmission

http://www.cenhud.com/dg

Con Edison

Provided in their interactive hosting capacity map:

Granularity: Substation and Circuit

https://www.coned.com/en/business-partners/hosting-capacity

National Grid

Provided in the NWA tab of their System Data Portal:

Granularity: Circuit

https://ngrid.portal.esri.com/portal/home/signin.html?returnUrl=https%3A//ngrid.portal.esri.com/SystemDataPortal/NY/index.html

NYSEG and RG&E

Provided in their 2018 DSIP update:

Granularity: Circuit

http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b6D4F931F-B10D-438F-8288-2A77DBEDD364%7d

Orange & Rockland

Provided in their interactive hosting capacity map:

Granularity: Circuit

https://www.oru.com/en/business-partners/hosting-capacity

Load Forecasts

The methods for accessing distribution load forecast data, and the characteristics of those data, vary by utility.

Central Hudson Gas & Electric

Provided on their Distributed Generation web portal:

http://www.cenhud.com/dg

Con Edison

Provided on their Distributed System Platform web portal: https://www.coned.com/en/business-partners/hosting-capacity

National Grid

Provided via the Company Reports tab of their System Data Portal: https://ngrid.portal.esri.com/portal/home/signin.html?returnUrl=https%3A//ngrid.portal.esri.com/SystemDataPortal/NY/index.html

NYSEG and RG&E

Provided in response to an emailed request to **NYRegAdmin@avangrid.com**.

Orange & Rockland

Provided via their interactive hosting capacity map:

Granularity: System, Area Station

https://www.oru.com/en/business-partners/hosting-capacity

Historical Load Data

The methods for accessing historical distribution load data, and the characteristics of those data, vary by utility.

Central Hudson Gas & Electric

Provided on their Distributed Generation web portal:

Granularity: Circuit

http://www.cenhud.com/dg

Con Edison

Provided on their Distributed System Platform web portal:

Granularity: System

https://www.coned.com/en/business-partners/hosting-capacity

National Grid

Provided via the Company Reports tab of their System Data Portal:

Granularity: Circuit
https://ngrid.portal.esri.com/portal/home/signin.html?returnUrl=https%3A//ngrid.portal.esri.com/SystemDataPortal/NY/index.html

NYSEG and RG&E

Historical load data are not currently available to the public.

Orange & Rockland

Provided via their interactive hosting capacity map:

Granularity: Area, Station

https://www.oru.com/en/business-partners/hosting-capacity

Non-Wires Alternatives (NWA) Opportunities

Non-Wires Alternatives can defer or eliminate the need for transmission & distribution infrastructure upgrades, meeting the dynamic needs of the electric system while reducing future rate pressure. Each of the following utility web sites provides the latest details about the utility's respective NWA opportunities and related solicitations.

Central Hudson Gas & Electric

Provided on their Non-Wires Alternative Opportunities web page:

https://www.cenhud.com/contractors/non-wires-alternative-opportunities/

Con Edison

Provided on their Non-Wires Solutions web page:

https://www.coned.com/en/business-partners/business-opportunities/non-wires-solutions

National Grid

Provided on their Non-Wires Alternatives web page:

https://www.nationalgridus.com/Business-Partners/Non-Wires-Alternatives/

NYSEG and RG&E

NWA information for NYSEG**:**

https://www.nyseg.com/wps/portal/nyseg/networksfooter/ourcompany/!ut/p/z0/hZBBawIxEIX_SnvYo0xW24JHEbGIW6kgrLksMYzpaDoTk7jt_vvu4sGe2tv3hsfHY0BDDZpNS85kEja-z3v90kzKavH6NFdvm_VmrN7Vajmd7raTXVnCCvRfBTUYxrGaVw50MPljRHwUqOUarXwGw91RJGP8z1MOHjpdLnoG2gpn_M5Qc5fQGRebu65Qv5ltE9GTOXhMGFuyWKjbgTzl7iFEOaHNqVADSeiBhUdfFDEZ3-_i_hEtJghnfXj27vEH4-cYgg!!/

NWA information for RG&E:

http://rge.com/SuppliersAndPartners/NonWiresAlternatives/ProjectOpportunities.html

Orange & Rockland

Provided on their Identified Non-Wires Alternatives Opportunities web page:
https://www.oru.com/en/business-partners/business-opportunities/non-wires-alternatives

Also provided on their Interactive Hosting Capacity Map:

https://www.oru.com/en/business-partners/hosting-capacity

Distributed Generation DG Information

Each utility monthly files with the New York Public Service Commission an updated SIR Inventory Report that presents the utility's DG interconnection data (queued and installed) in MS Excel and PDF formats. Those reports are accessible via the Department of Public Service's SIR Inventory Information web page:

http://www3.dps.ny.gov/W/PSCWeb.nsf/All/286D2C179E9A5A8385257FBF003F1F7E?OpenDocument

SIR Pre-Application Information

SIR Pre-Application information is provided to interconnection applicants on request and following registration on the utility-specific web sites listed below.

Central Hudson Gas & Electric

https://www.cenhud.com/dg/submit_interconnection_application

Con Edison

https://www.coned.com/en/save-money/using-private-generation-energy-sources/applying-for-interconnection

National Grid

https://www9.nationalgridus.com/niagaramohawk/business/energyeff/4_app-pkg.asp

http://arcg.is/28XscPy

NYSEG

https://www.nyseg.com/wps/portal/nyseg/saveenergy/!ut/p/z1/tZNBb4IwFID_yi4cSatY1CNzBGcUpsiAXkilHauRgrVz-u8ti3HbQVmW2Ntr3nv9-vUVYJAALMieF0TxSpCNjlNsZ1Zn5o57I-gH06AL53DiDYfRwnInfRDfSnBCBPBf6uGV5cC2-leAAc6FqtU7SMVxxwpSyGxXEqmYYLI4GvBXIPKMC1Htvy5oQMp3SvLVh2K0aFLO25XYcMEe6koqLUGfUOecgnRo07xjMWK-dbvI7FmImStkM5NarI_yFSU5s5rseDTLvGnw6EyzUeAv3WQJUgP6aeh6jrfI_IthA44ZoUwaMGwg3TPk8w_Cp29C70J4W3vjBd-2GjeYLQ_X1iPVDP1rHV5sBOI9Z58gEpUstcXwfx7nkbvQJ91f6RiCSdu06e_A19stdvTMVUKxgwLJnYauLqOoHFilmcA1KsrBwfTiE750pUE!/dz/d5/L2dBISEvZ0FBIS9nQSEh/?current=true&urile=wcm%3Apath%3A%2Fnysegagr_smartenergy%2Fsmartenergy%2Fnc_innovation%2Fdistributedgeneration%2Fonline%2Bportal

RG&E

http://www.rge.com/SuppliersAndPartners/distributedgeneration/distributedgenerationonlineportalapplication.html

Orange & Rockland

https://www.oru.com/en/save-money/using-private-generation-energy-sources/applying-for-interconnection

Appendix B: Recommended IEDR Data Items

The following table lists Staff's recommended data items to be acquired, integrated, managed, analyzed and made accessible by the proposed IEDR.

The column labelled "Data Category" indicates whether a data item is represented by structured data (organized and sortable numbers, letters, words, and phrases) or unstructured data (documents, diagrams, images, and video items that are characterized by metadata).

The column labelled "Program Phase" indicates when the data item should be implemented in the IEDR. The number "1" indicates that the data item should be included as a part of the initial IEDR implementation. The number "2" indicates that the data item should be implemented at a later time, based on use case priorities. All data elements comprising the DER Industry Group's recommended Minimum Viable Data Set (MVDS) are incorporated within the set of data elements tagged with a "1".

Data Items	Data Category	Program Phase
Substation Details		
substation ID	structured	1
utility ID	structured	1
NYISO zone	structured	1
NYISO transmission node	structured	1
street address	structured	1
GIS coordinates	structured	1
Substation Bus Details		
bus ID	structured	1
substation ID	structured	1
utility ID	structured	1
Bus voltage	Structured	1
bus protection details	structured	1
bus-connected transformer IDs	structured	1
bus-connected circuit IDs	structured	1
Substation Transformer Details		
transformer ID	structured	1
substation ID	structured	1
utility ID	structured	1
transformer type	structured	1
transformer manufacturer	structured	1
transformer model	structured	1
transformer configuration	structured	1

Data Items	Data Category	Program Phase
transformer high-side bus ID	structured	1
transformer low-side bus ID	structured	1
transformer high-side voltage	structured	1
transformer low-side voltage	structured	1
transformer protection details	unstructured	1
transformer nameplate load rating	structured	1
transformer load factor	structured	1
transformer hourly load historical data	structured	1
transformer hourly load forecast data	structured	1
Circuit Details		
circuit ID	structured	1
connected substation ID(s)	structured	1
connected substation bus ID(s)	structured	1
utility ID	structured	1
NYISO zone	structured	1
NYISO transmission node	structured	1
nominal circuit voltage	structured	1
minimum load	structured	1
average load	structured	1
average daily peak load	structured	1
average time of daily peak load	structured	1
annual peak load	structured	1
annual peak load date-time	structured	1
load rating at the substation	structured	1
load factor at the substation	structured	1
circuit hourly load historical data	structured	1
circuit hourly load forecast data	structured	1
circuit length	structured	1
circuit protection details	unstructured	1
historical hosting capacity at the substation	structured	1
forecast hosting capacity at the substation	structured	1
historical hosting capacity at end of line	structured	1
forecast hosting capacity at end of line	structured	1
hosting capacity calculation methodology	unstructured	1
hosting capacity calculation inputs	unstructured	1
hosting capacity constraint reason(s)	unstructured	1
Service Transformer Details		
service transformer ID	structured	1
connected circuit ID	structured	1

Data Items	Data Category	Program Phase
connected phase(s)	structured	1
GIS coordinates	structured	1
utility ID	structured	1
NYISO zone	structured	1
NYISO transmission node	structured	1
transformer type	structured	1
transformer manufacturer	structured	1
transformer model	structured	1
transformer configuration	structured	1
transformer high-side voltage	structured	1
transformer low-side voltage	structured	1
transformer nameplate rating	structured	1
transformer load factor	structured	1
date installed	structured	1
Electric Service Point Details		
service point ID	structured	1
street address	structured	1
GIS coordinates	structured	1
utility ID	structured	1
NYISO zone	structured	1
NYISO transmission node	structured	1
connected circuit ID	structured	1
connected service transformer ID	structured	1
interconnection power rating	structured	1
meter ID	structured	1
service voltage	structured	1
number of phases	structured	1
average load	structured	1
average peak	structured	1
peak times	structured	1
load factor	structured	1
local energy value	structured	1
local capacity value	structured	1
applicable NWA opportunity ID	structured	1
measured consumption interval data	structured	1
synthesized consumption interval data	structured	1
hosting capacity at service location	structured	1
Electric Customer Details		
account ID	structured	1
utility ID	structured	1

Data Items	Data Category	Program Phase
service point ID	structured	1
service class	structured	1
customer name	structured	1
postal address	structured	1
phone number	structured	1
email address	structured	1
current tariff/program ID	structured	1
monthly billed demand	structured	1
monthly billed energy	structured	1
monthly billed service charge	structured	1
system peak load capacity contribution	structured	1
system peak load transmission contribution	structured	1
North American Industry Classification System (NAICS) code	structured	1
account start date	structured	1
account end date	structured	1
Electric Meter Details		
meter ID	structured	1
service point ID	structured	1
utility ID	structured	1
meter manufacturer	structured	1
meter model	structured	1
meter serial number	structured	1
meter configuration profile ID	structured	1
date installed	structured	1
date removed	structured	1
metering service provider ID	structured	1
Gas Service Point Details		
service point ID	structured	1
street address	structured	1
GIS coordinates	structured	1
utility ID	structured	1
connected pipeline ID	structured	1
interconnection flow rating	structured	1
meter ID	structured	1
average demand	structured	1
average demand peak	structured	1
demand peak times	structured	1
interconnection load factor	structured	1
applicable NPA opportunity ID	structured	1
measured consumption interval data	structured	1

Data Items	Data Category	Program Phase
synthesized consumption interval data	structured	1
Gas Customer Details		
account ID	structured	1
utility ID	structured	1
service point ID	structured	1
service class	structured	1
customer name	structured	1
postal address	structured	1
phone number	structured	1
email address	structured	1
current tariff/program ID	structured	1
monthly billed demand	structured	1
monthly billed energy	structured	1
monthly billed service charge	structured	1
North American Industry Classification System code	structured	1
account start date	structured	1
account end date	structured	1
Gas Meter Details		
meter ID	structured	1
service point ID	structured	1
utility ID	structured	1
meter manufacturer	structured	1
meter model	structured	1
meter serial number	structured	1
meter configuration profile ID	structured	1
date installed	structured	1
date removed	structured	1
metering service provider ID	structured	1
Steam Service Point Details		
service point ID	structured	1
street address	structured	1
GIS coordinates	structured	1
utility ID	structured	1
connected pipeline ID	structured	1
interconnection rating	structured	1
meter ID	structured	1
average demand	structured	1
average demand peak	structured	1
demand peak times	structured	1

Data Items	Data Category	Program Phase
interconnection load factor	structured	1
measured consumption interval data	structured	1
synthesized consumption interval data	structured	1
Steam Customer Details		
account ID	structured	1
utility ID	structured	1
service point ID	structured	1
service class	structured	1
customer name	structured	1
postal address	structured	1
phone number	structured	1
email address	structured	1
current tariff/program ID	structured	1
monthly billed demand	structured	1
monthly billed energy	structured	1
monthly billed service charge	structured	1
North American Industry Classification System code	structured	1
account start date	structured	1
account end date	structured	1
Steam Meter Details		
meter ID	structured	1
service point ID	structured	1
utility ID	structured	1
meter manufacturer	structured	1
meter model	structured	1
meter serial number	structured	1
meter configuration profile ID	structured	1
date installed	structured	1
date removed	structured	1
metering service provider ID	structured	1
Grid Sensor Details		
sensor ID	structured	1
utility ID	structured	1
circuit ID	structured	1
nearest service point ID	structured	1
sensor type	structured	1
sensor manufacturer	structured	1
sensor model	structured	1
sensor configuration profile ID	structured	1

Data Items	Data Category	Program Phase
sensor time-series measurement data	structured	1
sensor time-stamped event data	structured	1
date installed	structured	1
date removed	structured	1
Power Quality Event Details		
event ID	structured	1
utility ID	structured	1
sensor/meter ID	structured	1
event type	structured	1
event beginning date-time	structured	1
event end date-time	structured	1
Installed DER Details		
DER ID	structured	1
service point ID	structured	1
customer account ID	structured	1
site address	structured	1
site GIS coordinates	structured	1
utility ID	structured	1
current tariff/program ID	structured	1
DER type	structured	1
DER nameplate rating	structured	1
inverter type	structured	1
inverter nameplate rating	structured	1
inverter manufacturer	structured	1
inverter model	structured	1
inverter configuration	structured	1
owner ID	structured	1
operator ID	structured	1
historical power interval data	structured	1
forecast power interval data	structured	1
synthesized historical power interval data	structured	1
synthesized interval data	structured	1
date installed	structured	1
date removed	structured	1
Queued DER Details		
interconnection request ID	structured	1
interconnection queue position	structured	1
interconnection status	structured	1
utility ID	structured	1

Data Items	Data Category	Program Phase
circuit ID	structured	1
customer account ID	structured	1
site address	structured	1
site GIS coordinates	structured	1
planned current tariff/program ID	structured	1
DER type	structured	1
DER nameplate rating	structured	1
inverter type	structured	1
inverter nameplate rating	structured	1
inverter manufacturer	structured	1
inverter model	structured	1
inverter configuration	structured	1
owner ID	structured	1
operator ID	structured	1
forecasted power interval data	structured	1
planned operational date	structured	1
Forecasted DER Details		
forecasted DER ID	structured	1
utility ID	structured	1
circuit ID	structured	1
nearest service point ID	structured	1
nearest service point GIS coordinates	structured	1
forecasted DER type	structured	1
forecasted DER capacity	structured	1
forecasted power interval data	structured	1
forecasted operational date	structured	1
Registered Electric Vehicle Details		
VIN	structured	2
state registration ID	structured	2
state registration street address	structured	2
GIS coordinates for registration address	structured	2
EV type	structured	2
EV manufacturer	structured	2
EV model	structured	2
EV model year	structured	2
compatible charger type(s)	structured	2
maximum EV charging power (W)	structured	2
EV battery capacity (kWh)	structured	2
efficiency (miles per kWh)	structured	2
estimated annual miles	structured	2

Data Items	Data Category	Program Phase
registration start date	structured	2
registration end date	structured	2
Forecasted Electric Vehicle Details		
proxy EV ID	structured	2
zip code	structured	2
GIS coordinates for zip code post office	structured	2
EV type	structured	2
compatible charger type(s)	structured	2
estimated maximum EV charging power (W)	structured	2
estimated EV battery capacity (kWh)	structured	2
estimated efficiency (miles per kWh)	structured	2
estimated annual miles	structured	2
registration start date	structured	2
registration end date	structured	2
Installed Electric Vehicle Charger Details		
charger ID	structured	2
service point ID	structured	2
utility ID	structured	2
owner ID	structured	2
operator ID	structured	2
location category	structured	2
street address	structured	2
GIS coordinates	structured	2
charger access category	structured	2
charger class level	structured	2
number of charger ports	structured	2
charger manufacturer	structured	2
charger model	structured	2
nameplate maximum load rating	structured	2
average daily charging events	structured	2
peak daily charging events	structured	2
average charger load	structured	2
average daily peak charger load	structured	2
average time of daily peak load	structured	2
annual peak charger load	structured	2
annual peak charger load date-time	structured	2
meter ID	structured	2
metering service provider ID	structured	2
metered interval load data	structured	2
date installed	structured	2

Data Items	Data Category	Program Phase
date removed	structured	2
Forecasted Electric Vehicle Charger Details		
proxy charger ID	structured	2
nearest service point ID	structured	2
utility ID	structured	2
location category	structured	2
nearest service point street address	structured	2
nearest service point GIS coordinates	structured	2
charger access category	structured	2
charger class level	structured	2
number of charger ports	structured	2
nameplate maximum load rating	structured	2
forecasted average daily charging events	structured	2
forecasted peak daily charging events	structured	2
forecasted average charger load	structured	2
forecasted average daily peak charger load	structured	2
forecasted average time of daily peak load	structured	2
forecasted annual peak charger load	structured	2
forecasted annual peak charger load date-time	structured	2
forecasted date installed	structured	2
Registered ICE Vehicle Details		
VIN	structured	2
state registration ID	structured	2
state registration street address	structured	2
GIS coordinates for registration address	structured	2
vehicle type	structured	2
vehicle manufacturer	structured	2
vehicle model	structured	2
vehicle model year	structured	2
fuel type	structured	2
fuel efficiency	structured	2
estimated annual miles	structured	2
registration start date	structured	2
registration end date	structured	2
Forecasted ICE Vehicle Details		
proxy vehicle ID	structured	2
zip code	structured	2
GIS coordinates for zip code post office	structured	2

Data Items	Data Category	Program Phase
vehicle type	structured	2
fuel type	structured	2
estimated fuel efficiency	structured	2
estimated annual miles	structured	2
registration start date	structured	2
registration end date	structured	2
Existing Building Details		
building ID	structured	2
service point ID	structured	2
utility ID	structured	2
street address	structured	2
GIS coordinates	structured	2
building owner	structured	2
building property manager	structured	2
building type	structured	2
building size	structured	2
zoning classification	structured	2
building energy consumption data - electric	structured	2
building energy consumption data - gas	structured	2
building energy consumption data - other	structured	2
Forecasted New Building Details		
proxy building ID	structured	2
nearest service point ID	structured	2
utility ID	structured	2
street address	structured	2
GIS coordinates	structured	2
building owner	structured	2
building property manager	structured	2
building type	structured	2
building size	structured	2
zoning classification	structured	2
building energy consumption data - electric	structured	2
building energy consumption data - gas	structured	2
building energy consumption data - other	structured	2
Forecasted Building Modification Details		
building ID	structured	2
service point ID	structured	2
utility ID	structured	2
street address	structured	2

Data Items	Data Category	Program Phase
GIS coordinates	structured	2
building owner	structured	2
building property manager	structured	2
building type	structured	2
building size	structured	2
zoning classification	structured	2
building energy modification type	structured	2
forecasted building electricity consumption data	structured	2
forecasted building gas consumption data	structured	2
forecasted building energy consumption data - other	structured	2
Digitized Bulk Power Market Details		
NYISO tariffs	unstructured	1
NYISO DR Manual	unstructured	1
NYISO Gold Book	unstructured	1
NYISO zone pricing histories	structured	1
NYISO transmission node pricing histories	structured	1
NYISO DER aggregation rules	unstructured	1
NYISO DER participation rules	unstructured	1
Digitized Distribution Network Value Details		
distribution tariffs	unstructured	1
machine-readable distribution tariffs	structured	1
distribution rate sheets	unstructured	1
machine-readable distribution rate sheets	structured	1
demand response program documents	unstructured	1
locational system relief value tables	structured	1
machine-readable locational system relief value tables	structured	1
BCA Handbook	unstructured	1
value stack calculator link	structured	1
Distribution Investment Plan Details		
utility ID	structured	1
project ID	structured	1
substation ID	structured	1
circuit ID	structured	1
nearest service point ID	structured	1
type of service need	structured	1
amount of service needed	structured	1
project completion date	structured	1
estimated wire-based solution cost	structured	1

Data Items	Data Category	Program Phase
Distribution NWA Opportunity Details		
utility ID	structured	1
NWA ID	structured	1
substation ID	structured	1
circuit ID	structured	1
nearest service point ID	structured	1
type of service need	structured	1
amount of service needed	structured	1
service need start date	structured	1
service need end date	structured	1
estimated wire-based solution cost	structured	1
NWA value	structured	1
Metadata for Digitized Documents & Other Unstructured Data Items		
item ID	structured	1
item type	structured	1
item source	structured	1
date most recently published	structured	1
update frequency	structured	1
next scheduled update	structured	1
digitized format	structured	1
web link to current version	structured	1
web links to previous versions	structured	1