REVIEW OF NOVA SCOTIA POWER'S TRANSMISSION AND DISTRIBUTION INTERCONNECTION PROCESSES

Final Report for M10905

Prepared for Nova Scotia Utility and Review Board

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CONTENTS

EXECUTIVE SUMMARY ES-1

1. INTRODUCTION 1

1.1. Background and Purpose 1

1.2. Terms of Reference 2

1.3. Stakeholder Engagement 2

Initial Comments – May 3 and May 31 3

July 12 Comments 4

August 10 Comments 5

2. GENERATION INTERCONNECTION PROCEDURES 6

2.1. Standard Generator Interconnection Procedures Review 9

Interconnection Request 9

Feasibility Study 10

System Impact Study 10

Facilities Study 10

Generator Interconnection Agreement 11

2.2. Distribution Generator Interconnection Procedures Review 11

Preliminary Assessment 11

Distribution System Impact Study 12

Standard Small Generator Interconnection Agreement 13

3. INTERCONNECTION PROCEDURE SUBSTANTIVE ISSUES 14

3.1. Interconnection Queue and Study Timing, OATT Compliance and Resource Sufficiency for Interconnection Studies 14

Overview and Queue Data Summary 14

Interconnection Queue Study Timelines and Bottlenecks 20

OATT Compliance 21

FERC Order 2023 24

Sufficiency of Resources to Conduct Interconnection Studies 26

Suggested Issues Resolution 27

3.2. Commercial Net Metering Issues 28

3.3. Energy Storage Considerations 31

3.4. Fast Tracking for Interconnection Studies and Threshold Capacity Size for Class 2 Distributed Resources 33

3.5. Hosting Capacity 35

Overview 35

Hosting Capacity Efforts in Other Jurisdictions 41

3.6. Study Grouping and Cost Allocation 43

Transmission 43

Distribution 44

4. RECOMMENDATIONS ON SUBSTANTIVE ISSUES 48

4.1. Overview 48

4.2. Transmission System Interconnection 49

4.3. Distribution System Interconnection 52

Appendix A: NSPI Transmission and Distribution Interconnection Queues (September 2023)

Appendix B: Other Jurisdictions – Canada and the US

Appendix C: Slide Presentations at Technical Conferences

Appendix D: Interstate Renewable Energy Council (IREC) Model Interconnection Procedures (2023)

EXECUTIVE SUMMARY

The Nova Scotia Utility and Review Board initiated this generation resource interconnection review process in 2022, in response to Provincial legislation seeking to ensure the best value for ratepayers and consistency and predictability for generators. Synapse has conducted two public technical conferences, solicited multiple rounds of stakeholder comment, and produced initial, interim and this final report containing our findings and recommendations concerning Nova Scotia Power, Inc. (NSPI) generation interconnection procedures or protocols.

New generation resource interconnection, especially of renewable energy sources, and battery energy storage interconnection play crucial roles in helping Nova Scotia to meet its recently expanded greenhouse gas emission targets. Nova Scotia Power's transformation from a utility using primarily fossil fuels (coal and gas) for a large majority of electricity production to using (by 2030) 80% renewable sources (both imports and internal generation) directly shapes a requirement to analyze and study the ability to interconnect new renewable resources, across the transmission grid and across the distribution grid. NSPI's generation interconnection procedures (GIPs) or protocols, generally originating from NSPI's adoption of an open access transmission tariff (OATT) roughly twenty years ago, require updating to allow for efficient – i.e., faster - study processes to reduce delays and allow economic resource development to proceed under the non-discrimination provisions of the OATT. An analogous set of protocols exist and require updating - for interconnection to the distribution system - as lower cost small scale renewable resources seek to interconnect.

The review encompasses examination of core substantive Issues: battery energy storage provisions in the protocols; grid impact study structures, timelines and fees; the size thresholds and associated ability for NSPI to "fast track" the study of Class 2 small resources interconnecting to the distribution grid; the overlap of distributed resource interconnection with the outcome of the Commercial Net Metering Program case; how the hosting capacity information provided by NSPI supports interconnection of new small resources, and how such information provision should evolve; how to allocate costs of network upgrades that generally benefit multiple parties, including ratepayers, but are initiated from a single resource interconnection request; and the overall efficiency of NSPI's interconnection queuing process, which allows developers to request and NSPI to examine the reliability needs for new resource interconnection, generally using renewable energy sources and battery energy storage systems.

NSPI has directly indicated planned changes to different aspects of its transmission and distribution system interconnection procedures. They plan to introduce a new threshold to allow faster tracking of resource interconnection requests for larger (than Class 1 threshold) resources that utilize inverters for connection to the power system (both solar PV, and batteries use inverters), at 500 kW and 1 MW instead of 100 kW. They have introduced a new 10 MW threshold to characterize small transmission connected resources and allow for faster studies and likely reduced study fees. They have directly indicated they are amenable to directly incorporating battery energy storage provisions into the procedures to appropriately study the impact that controllable battery systems can have on the grid. They plan to update an August 2023 release of their first distribution system hosting capacity tabulation.

In this report we discuss those substantive issues and develop a set of recommendations for modification to the Standard Generation Interconnection Procedures (SGIP)[1] and the Distribution Generation Interconnection Procedures (DGIP)[2].

While we generally support NSPI's planned modifications, we offer stretched recommendations in three specific ways:

1) a sustained increase in NSPI's ability to conduct interconnection studies, rather than temporary increases in such resources,

2) a move towards a distribution network upgrade cost allocation approach that recognizes other beneficiaries to distribution network upgrades beyond just the first mover interconnection customer (IC), and

3) a recommendation to advance to a dynamic hosting capacity information dissemination approach that aims for "coordination" with distributed energy resource providers to provide the maximum benefit to ratepayers from technologies that have the ability to directly support NSPI's reliability needs.

We also recommend reporting on a regular basis to allow for NSUARB and stakeholder review of progress in better enabling faster interconnection study and eventual deployment of studied resources onto the grid.

Lastly, our recommendations include both an initial stage of update to core SGIP and DGIP documents, but also - as necessary - a second round of updates in later 2024. While our near-term recommendations reflect an immediate take on FERC's Order 2023 (released July 28, 2023), we recommend NSPI conduct a deliberate, unhurried review of the Order, which encompasses improvements to interconnection procedures under the guise of FERC's open access transmission tariff and supporting structures.

The substantive elements of FERC Order 2023 reflect the same issues Nova Scotia is tackling: how to improve interconnection study timelines, how to assure fairness in interconnecting new resources from non-incumbent entities, and how to proceed with updating the provisions of the *pro forma* OATT to produce effective outcomes and increase both the speed and the overall magnitude of new connections for renewable resources onto the grid.

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[1] *Standard Generation Interconnection Procedures (GIP) (Applicable to Generating Facilities Connected to or Impacting the Transmission System at Voltages of 69 kV and above).* Nova Scotia Power, As Revised June 10, 2016. Available at https://www.nspower.ca/docs/default-source/pdf-to-upload/revised-standard-generation-interconnection-procedure-gip-20160dd2f99a2cd644a8be336fb7a36c5860.pdf?sfvrsn=4a29ba3f_0.

[2] *Distribution Generator Interconnection Procedures (DGIP) (Applicable to Generating Facilities > 100 kW Connected to Distribution Systems Rated ≤ 26,400 V, Including Class 2 Net Metering Service*). Nova Scotia Power, August 30, 2019. Available at https://www.nspower.ca/docs/default-source/pdf-to-upload/dgip.pdf?sfvrsn=290d4fa0_5.

1. INTRODUCTION

This report finalizes the two earlier versions of Synapse reporting on NSPI's interconnection procedures. The first report was issued as an initial Technical Report for M10905 on April 11, 2023. A Revised Report was issued on July 5, 2023 following the first technical conference. This Final Report includes additional insights from discussion during the July 19, 2023 technical conference and from stakeholder filings of August 10, 2023. It also considers the release of FERC's Order 2023 on interconnection reforms in July.

1.1. Background and Purpose

On April 22, 2022, the Nova Scotia legislature passed Bill No. 145 requiring Nova Scotia Utility and Review Board (NSUARB or Board) to review Nova Scotia Power Incorporated's (NSPI) process for interconnecting energy resources to the electricity grid. Specifically, the bill included the addition of Section 2C to the *Electricity Act*. Section 2C states: 2C (1) The Board shall conduct a review of Nova Scotia Power Incorporated's interconnections process to ensure the best value for ratepayers and consistency and predictability for generators; and (2) The Board shall undertake the review pursuant to subsection (1) as soon as is reasonably possible and shall make the results of the review public. NSUARB commissioned Synapse Energy Economics, Inc. (Synapse) to conduct that review.

The purpose of this Final report is to convey the results of our review of NSPI's interconnection processes, and to describe currently planned and recommended updates to NSPI's interconnection protocols and associated documentation.

This report outlines the GIP requirements, with attention to the fees and timelines at each stage. It also discusses the extent to which the GIPs address issues such as the interconnection queue, hosting capacity, group studies, cost allocation, energy storage systems, and distributed energy resources (DERs). Where applicable, the report compares these to model interconnection procedures (generally for distribution concerns) and activities in other jurisdictions (including recent FERC Order 2023 reforms) to inform the Board on the emerging trends and best practices related to each interconnection sub-topic.

The review encompasses NSPI's interconnection protocols for generation and storage resources connected both to the bulk system and to the distribution system. Central to this review is the need for NSPI's framework to adapt as the energy resource mix transforms: new renewable and battery energy storage resources will likely make up increasing shares of the Provincial electricity supply mix, and those will need fair and timely (if not expedited) review for interconnecting to either the transmission or distribution grid.

1.2. Terms of Reference

NSUARB issued Terms of Reference (TOR) to guide the review of NSPI's interconnection protocols. The TOR included processes for information exchange and discussion at stakeholder conferences, and a focus on at least the following substantive issues associated with NSPI's interconnections processes:

- **Bias in Treatment**: Overall adherence of the interconnection processes and requirements to the spirit and letter of the open access transmission tariff (OATT), for provision of non-discriminatory access to the transmission and distribution grid. Consideration of the extent to which NS Power's protocols or implementation practicalities result in a bias towards NS Power or Emera self-interest, and against third-party generator interests.

- **Timing of Studies**: specific elements of the SGIP or the DGIP documents that may require improvement, including feasibility, system impact, and facilities study timelines. This could also include assessing technical requirements under the SGIP, including those affecting behind-the-meter facilities interconnected at the transmission level.

- **Study Requirements**: a review of the fee structure and applicability for interconnection studies, including consideration of whether the threshold size level (100 kW) for the distribution system should be revisited for interconnection studies.

- **Cost Allocation**: a review of whether interconnection cost allocation methods adequately, equitably and fairly distribute the system upgrade costs that may be necessary and assessment of how and to what extent interconnection processes and requirements accommodate and allocate system upgrade costs fairly and reasonably among groups of interconnection customers through interconnection cluster studies or other methods.

- **Communication and Transparency**: a review of the overall communications processes and methods that allow NSPI and those requesting interconnection to exchange data and information in an efficient, transparent, and timely manner, informed by a limited review of other relevant jurisdictions interconnection processes and requirements.

- **Energy Storage**: a review of whether interconnection processes and requirements are sufficient for non-generation technologies, such as battery energy storage systems.

- **Technical Requirements**: consideration of the published transmission and distribution interconnection requirements, and whether they are sufficient, insufficient, or exaggerated for the purposes to which they are ascribed.

1.3. Stakeholder Engagement

A draft version of the Terms of Reference was released in December of 2022. Stakeholder comments received in early January were incorporated, and the NSUARB circulated a final version of the TOR to stakeholders on February 10, 2023.

Synapse released an initial technical report on April 11, 2023 containing a description of the issues for consideration. The initial technical report provided a framework for the first stakeholder technical conference on May 17, 2023, which led to specific discussions on major issue areas. A revised report was released on July 5, a second technical conference was held on July 19, and this final report is planned for release in September.

Comments were received from stakeholders on May 3 (in response to the initial report), May 31 (following the first technical conference), July 12 (following the release of the revised report), and August 10 (following the second technical conference).

The following stakeholders submitted comments or participated in technical conference discussions during the process:

1. SWEB Development LP
2. Nova Scotia Department of Natural Resources and Renewables
3. Energy Storage Canada
4. Roswall Development Inc.
5. Rimot
6. Small Business Advocate
7. Alternative Resource Energy Authority
8. Polycorp Group of Companies
9. NRStor Incorporated
10. Canadian Renewable Energy Association
11. Solar Nova Scotia

Initial Comments – May 3 and May 31

Stakeholder comments were submitted on May 3, 2023 prior to the first technical conference. The following issues were addressed in those comments:

- Updating Generator Interconnection Procedures (GIPs) and related rules to better accommodate energy storage,
- Revisiting the 100kW DGIP threshold for Class 2 resources and the associated study fee structures,
- Improving hosting capacity reporting and system modeling,
- Considering OATT compliance, bias, conflict of interest, etc., and
- Cost-sharing or cost allocation of network upgrades (transmission) or distribution system upgrades beyond the immediate point of interconnection.

Additional comments were submitted by five stakeholders on May 31, 2023 following the first technical conference.

- Polycorp reiterated its concerns over the size threshold for Class 2 resources.

- Energy Storage Canada posed questions to NSPI and Synapse concerning battery storage resources, fast tracking of interconnection requests, and hosting capacity details.
- NRR submitted extensive comments on the potential for biased treatment in the interconnection queuing process, cost allocation issues facing interconnection customers, the nature of fee structures and timelines in other jurisdictions, Class 2 threshold capacity size considerations, and the use of cluster studies.
- RIMOT's comments requested consideration of electric vehicle supply equipment (EVSE) or charging equipment within the DGIP.
- NRStor expressed concern over the nature of the requirement for an energy revenue contract as part of the SGIP as a barrier to moving through the process; and also commented on fee structures, energy storage considerations, hosting capacity, and bias in interconnection study treatment.

July 12 Comments

After these comment submissions at the end of May, a Revised Report was released by Synapse on July 5, 2023. PHP Wind, Energy Storage Canada, NRStor, Solar Nova Scotia and the Small Business Advocate submitted comments on the report on July 12. Those comments included the following concerns:

- Barriers to Moving Through the Interconnection Process
  - Assumptions that NSPI is making for ESS charging and dispatching should be revised,
  - Requirements to move through the SIS process are onerous for the majority of interconnection customers, and most requirements in Section 7.2(vii) of the SGIP do not apply to most customers,
  - Revisions need to be made to GIP requirements for entering the SIS queue to specifically allow for a behind-the-meter, self-supply project to enter the queue,
  - Small generating facilities should also be included as a class of ESS project so fast-tracking is available for ESS,
  - Strictly following the queue order is not ideal in the case of a later timestamped project that could increase the hosting capacity for other ICs.
- Fee Structures
  - Study fees should be set at a level competitive with other jurisdictions, should eliminate re-study deposits, and should reflect actual study costs.
- Treatment of ESS
  - ESS should be differentiated in the interconnection procedure pathways from generation,
  - Non-material additions or modifications should be included as a class of ESS project for the GIP and DGIP,
  - The project capacity size threshold should be reconsidered for ESS compared to generation.

In those comments, PHP Wind supports the recommendation to adopt changes to NS Power's interconnection procedures, including changes to improve transparency going forward. NRStor asks for Synapse to expand the recommendations section of the Revised Report. Solar Nova Scotia seeks an increase in the threshold to Class 2 resource size beyond 100 kW and notes its concern that the cost causer approach for distribution system upgrade requirements may be unfair as it can lead to free riding by subsequent participants.[3] The Small Business Advocate also reiterates its concern regarding distribution system cost upgrade responsibilities and its expectation that the second technical conference would address this issue.

A second technical conference was held on July 19, and three stakeholders, in addition to NSPI, submitted comments on August 10.

August 10 Comments

NSPI submitted an extensive array of comments and suggestions for resolving issues addressed throughout the process. Those are directly included in the issue area descriptions and recommendations that follow in this report. These comments follow from NSPI's May 3 comments which indicated their plans to update specific sections of the SGIP, DGIP and supporting documents.

NRR and Solar Nova Scotia (SNS) also submitted comments in early August. NRR reiterated its concern with the potential for bias in the treatment of interconnection queuing and study issues between NSPI and non-NSPI interconnection customers. SNS notes that it expects the majority of solar PV projects in the province over the next ten years to be either Commercial Net Metering Program (CNMP) at less than 1 MW, or Community Solar projects between 1 and 10 MW. SNS reiterates its key concerns regarding threshold capacity levels for Class 2, service standards for interconnection and application of Class 2 CNMP projects, and the fairness of the cost causation approach for distribution system upgrade costs. It also notes the importance of hosting capacity information, consideration of a pre-application report (as ordered by the Board in the CNMP Decision Letter) for non-CNMP customers and noting that Community Solar installations are commencing or are about to commence in the province this fall.

In response to the TOR, in alignment with the initial report, and considering stakeholder comments, the core issue and discussion items considered during the technical conferences, and addressed in stakeholder comments as highlighted above include:

1. Interconnection Queue and Related Studies' Timelines and Fees
2. Overlap with Commercial Net Metering (M10872) Issues
3. Energy Storage as a Separate Resource Type for SGIP and DGIP Interconnection Study
4. Threshold Capacity Size for Class 2 Distributed Resources
5. Distribution System Hosting Capacity
6. Cost Allocation for Distribution Connection Costs for Distributed Generation or Storage

Synapse has also suggested consideration of the merits of various issues and practices addressed or contained in the Interstate Renewable Energy Council (IREC) documents in support of determining and

[3] NSPI notes in its comments on May 3 and August 10 that it is amenable to the development of regulations to ensure a refund mechanism for any distribution system cost upgrades from first movers, to prevent such free riding concerns from subsequent users.

interpreting the best practices for interconnection protocols to inform any changes to NSPI's GIPs. NSPI has noted that in a number of instances, NSPI's GIPs' fee structures or other metrics are lower cost (fees) or more progressive (e.g., capacity threshold for Class 1 and Class 2 resources for fast tracking interconnection processes including studies).

RIMOT provided comments on vehicle-to-grid (V2G) technologies, encouraging including bi-directional Electric Vehicle Supply Equipment in the DGIP in support of BESS marine vessels and commercial vehicles. NSPI responded that under the Smart Grid Nova Scotia (SGNS) project, it has been studying the potential in bi-directional capabilities as they apply to BESS and will report later in 2023 to NSUARB on potential GIP amendments and believes consideration of bi-directional and vessel- or V2G capabilities in any GIS amendments would benefit from those report results. As part of any SGIP or DGIP update, including technical interconnection requirement updates, we recommend NSPI consider and include these technologies appropriately.

2. Generation Interconnection Procedures

Generation Interconnection Procedures (GIP) include all procedures, terms, and required forms and data governing how interconnection customers (ICs) may apply and interconnect to Nova Scotia's transmission or distribution grid. Facilities with a nameplate capacity exceeding 100 kW and connected at distribution voltages less than or equal to 26.4 kV are subject to Distribution Generation Interconnection Procedures (DGIPs), whereas facilities connecting at voltages equal to or greater than 69 kV (i.e., transmission) are subject to Standard Generation Interconnection Procedures (SGIPs).

GIPs instruct ICs how they can enter and advance through the interconnection queue and what requirements ICs must satisfy at each stage. Specifically, the GIPs specify the various interconnection studies NSPI must undertake before interconnecting a facility, the timelines of such studies and communications between NSPI and the IC, and the fees involved at each stage. At each study stage in the GIPs generally, NSPI must use "reasonable efforts"[4] to complete studies in a timely manner. In the event of delays, NSPI must provide notice and explanations to the IC as to why there is a delay. The GIPs also contain general provisions on how disputes between NSPI and an IC will be resolved, which essentially require parties to go through arbitration if no resolution is forthcoming.

When an IC submits its interconnection request and upon NSPI's verification that such application is complete, the IC enters the interconnection queue. The IC's queue position is tied to the date of a completed interconnection request.[5] After the interconnection feasibility study (for transmission requests), an IC may advance through the queue and receive a prioritized queue position by establishing it has met all progression milestones under the Interconnection System Impact Study (SIS)

[4] FERC Order 2023, from July 28, 2023, has eliminated this standard and replaced it with a penalty system for late studies.

[5] This is true for both Transmission and Distribution ICs.

requirements. After the preliminary assessment (for distribution requests), an IC may advance through the queue and receive a prioritized queue position by establishing it has met all progression milestones under the Distribution System Impact Study (DSIS) requirements. ICs who withdraw are not formally penalized, although they would lose their queue position and would have to move to the back of the line, so to speak, if they wished to proceed with interconnection.[6] Tables 1 and 2 below summarize the application, study structure, timeline, process and criteria by interconnection request size and type.

Table 1. Current application and study fee structure by size and type of resource – Distribution Connection

Size and Type	Process	Application Fee/ Parameters	Study Fee / Parameters	Timeline	Technical criteria / Other
Class 1: Generation ≤ 100 kW[7]	(1) Interconnection Request (2) Class 1 Interconnection Agreement	None	None	Not provided	A DSIS may be required when multiple adjacent generators request interconnection with aggregate capacity over 100 kW[8]
Class 2: Generation ≥ 101 kW[9]	(1) Interconnection Request (2) Preliminary Assessment (3) Distribution System Impact Study (4) Standard Small Generator Interconnection Agreement	$750 per interconnection request	$10,000 refundable deposit. Applicants are invoiced for actual costs with the deposit applied or refunded to the balance as applicable. Optional additional study deposit of $7,500 at request of IC.	(1) NSPI will acknowledge receipt of the Interconnection Request within 5 business days. (2) NSPI will attempt to complete the Preliminary Assessment within 30 days. (3) NSPI will attempt to complete the DSIS within 90 calendar days.	NSPI will group studies (cluster) within zones. NSPI can fast-track projects that the preliminary assessment shows will not have a material impact on the distribution system.

[6] SGIP, page 30, DGIP, page 11.

[7] *Interconnection Requirements: Generating Facilities Not Exceeding 100 kW (Connected to Distribution Systems Rated ≤ 26,400 V)*, Nova Scotia Power (August 14, 2020). Available at: https://nspower-stage-ca.aws.silvertech.net/docs/default-source/default-document-library/interconnection-requirements-for-not-exceeding-100-kw---august-14-2020.pdf?sfvrsn=c2bbb889_2. Synapse assumes generation sizes less than 101 kW but greater than 100 kW are truncated to the Class 1 category, based on the more recent September 1, 2023 M10872 filing. See footnote 9 below.

[8] NS Power Comments on Synapse Interconnections Processes Report, Attachment 1.

[9] *Interconnection Requirements: Generating Facilities > 100 kW (Connected to Distribution Systems Rated ≤ 26,400 V)*. Nova Scotia Power (August 14, 2020). Available at: https://www.nspower.ca/docs/default-source/pdf-to-upload/interconnection-requirements-generating-facilities-above-100kw.pdf?sfvrsn=fc0424ee_12. Also, "Overview of Pre-Application Assessment Process (For Systems with Capacity ≥ 101 kW)", M10872 – Commercial Net Metering Program Proposed Pre-Application Report and Process, Attachment 3 (Revised August 29, 2023). Filed September 1, 2023. Based on the more recent September 1, 2023 M10872 filing, Synapse assumes that any generation less than 101 kW yet greater than 100 kW is considered as Class 1 generation. The August 2020 Interconnection Requirements document could be interpreted to classify resources with a size greater than 100 kW but less than 101 kW as Class 2.

Table 2. Current application and study fee structure by size and type of resource – Transmission Connections

Size and Type	Process	Study Fee / Parameters	Timeline	Technical criteria / Other
<20 MW[10]	No application fee, but FEAS deposit is paid with interconnection request.[11] (1) Interconnection Request (2) Feasibility Study (FEAS) (3) System Impact Study (SIS) and Re-study (4) Facilities Study (FAC) and Re-study (5) Standard Generator Interconnection and Operating Agreement For all study fees, applicants are invoiced for actual costs with the deposit applied or refunded to the balance as applicable.	FEAS: $15,000 SIS: $50,000 SIS Re-study: $100,000 FAC: $25,000 FAC Re-Study: $25,000	1) NSPI will acknowledge receipt of the Interconnection Request within 5 business days. (2) NSPI will attempt to complete the FEAS within 45 days and the re-study within 45 days. (3) NSPI will attempt to complete the SIS within 120 days and re-study within 60 days. (4) NSPI will attempt to complete the FAC within 120 days and re-study within 60 days.	NSPI will group studies based on queue position. NSPI can expedite the interconnection process for small generating facilities.
>20 MW, <50 MW[12]		FEAS: $15,000 SIS: $75,000 SIS Re-study: $150,000 FAC: $50,000 FAC Re-Study: $50,000		
>50 MW, <150 MW[13]		FEAS: $15,000 SIS: $100,000 SIS Re-study: $200,000 FAC: $50,000 FAC Re-Study: $50,000		
>150 MW[14]		FEAS: $15,000 SIS: $150,000 SIS Re-study: $300,000 FAC: $75,000 FAC Re-Study: $75,000		

NSPI has submitted Class 1 CNMP service standards[15] (with timelines and fees)[16] and plans to update Class 2 CNMP service standards.

For those Class 2 facility sizes, NSPI has proposed for fast-tracked resources a distribution connection process at a lower DSIS study fee deposit of $2,500 for IBR (inverter-based resources) that are either i) less than 500 kW (at feeder voltages of 12.5 kV), or ii) less than 1 MW (1,000 kW) at voltages of 25 kV.[17]

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[10] *Standard Generator Interconnection Procedures (GIP)*, Nova Scotia Power (2016). Available at: https://www.nspower.ca/docs/default-source/pdf-to-upload/revised-standard-generation-interconnection-procedure-gip-20160dd2f99a2cd644a8be336fb7a36c5860.pdf?sfvrsn=4a29ba3f_0.

[11] An additional deposit of $20,000 is required, or applicants must "demonstrate ownership, leasehold interest, development rights, or option to purchase/acquire interest in a land area at least 50% required to construct the facility", NSPI August 10, 2023 comments, Figure 1 at page 9.

[12] Ibid.

[13] Ibid.

[14] Ibid.

[15] August 3, 2023, M10872 30 day report filing.

[16] https://www.nspower.ca/your-business/save-money-energy/make-own-energy/commercial-net-metering

[17] NSPI Comments, August 10, 2023, pages 4 and 7.

NSPI has proposed a separate study and fee category[18] for transmission-connected resources less than or equal to 10 MW. This would apply, for example, to most Community Solar projects. The current study deposit amount is $50,000; NSPI does not recommend a specific study deposit for these smaller projects in its comments. We recommend NSPI include a suggested amount in its compliance filing.

NSPI recommends that changes to Section 7.2 (vii) of the SGIP, which allows an interconnection customer to move to the SIS stage, be limited to inclusion of behind-the-meter generation.

2.1. Standard Generator Interconnection Procedures Review

The general order of procedures for a standard IC is as follows:

- Interconnection Request
- Feasibility Study
- System Impact Study (SIS)
- Facilities Study
- Generator Interconnection Agreement (GIA)

The SGIPs apply to facilities interconnecting to the transmission system at voltages at 69 kV and above. The IC must select in their interconnection requests whether they want Energy Resource Interconnection Service or Network Resource Interconnection Service. Energy Interconnection Service constrains the IC's line utilization based on "as available" line capacity, whereas Network Interconnection Service allows for a facility's full generation output. According to the OASIS interconnection queue data, no IC currently in the queue has opted for Energy Resource Interconnection Service.

Interconnection Request

To submit a complete interconnection request, ICs must deposit $15,000, a completed request form, and either proof of some form of interest in at least 50 percent of the land at the facility's site or a $20,000 additional deposit. The request form must specify the exact point of interconnection through a one-line diagram. The queue position and progression for ICs is the same as for DSIS, meaning that demonstration of progression milestones can accelerate ICs interconnection through a prioritized queue position.

- **Fee**: $15,000 study deposit
- **Timeline**: NSPI has five business days to acknowledge receipt and notify the IC of any deficiencies, after which the IC has 10 business days to respond. The parties must establish a meeting date within 10 business days of the request and then meet within 30 calendar days

[18] NSPI Responses to ESC Information Requests, Response IR-1.1; NSPI Comments, August 10, 2023, pages 4 and 7.

of the request to conduct a scoping meeting. NSPI will render the feasibility study agreement at that time.

Feasibility Study

The Feasibility Study is analogous to the Preliminary Assessment described in the DGIP process in Section 2.2. It assesses the feasibility of the proposed interconnection, including any potential adverse system impacts that would result from the IC facility's interconnection. The study consists of power flow and short-circuit analyses. NSPI must provide the IC with a non-binding, good-faith cost estimate and timeline for any necessary construction related to interconnection.

- Fees: Initial study deposit used.
- Timeline: The study must finish no later than 45 days after execution of Feasibility Study agreement. NSPI must then meet with the IC within 10 business days of the final Feasibility Study report. Within three business days of the Feasibility Study meeting, NSPI must provide the IC with a non-binding good-faith estimate of the cost and timeframe for completing the Interconnection System Impact Study.

System Impact Study

The SIS evaluates the impact of the proposed interconnection on the reliability of the transmission system.[19] In the SIS, NSPI will conduct a comprehensive short-circuit analysis, power flow analysis, and a stability analysis. Two major products of the SIS are (1) a list of facilities that will be required to interconnect the IC's facility and (2) a good-faith estimate of the construction cost (including overheads).

- **Fees**: The IC customer must pay the actual costs of the SIS and pay the corresponding study deposit, as seen in Table 2.
- **Timeline**: The IC must execute the SIS agreement within 30 calendar days of receipt and issue the corresponding deposit amount:[20] NSPI must use reasonable efforts to complete the SIS within 120 calendar days. The parties must meet within 10 business days of issuing the SIS report.

Facilities Study

The Facilities Study shall specify and estimate the cost of the equipment, engineering, procurement, and construction work needed to implement the conclusions of the SIS. This involves studying the construction of facility's corresponding network upgrades and other interconnection costs. It is contingent on NSPI and the IC to negotiate a schedule for the construction.

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[19] SGIP, 10. A system impact study identifies the electric power system (EPS) impacts that can result if a proposed DER is interconnected without modifications. The impact study focuses on potential adverse effects to the operation, safety, and reliability.

[20] SGIP, 42.

- **Fees**: The IC customer must pay the actual costs of the Facilities Study and pay the corresponding study deposit, as seen in Table 2.

- **Timeline**: Within three business days of the SIS final report meeting, NSPI must provide a non-binding good-faith estimate for the Facilities Study and indicate the corresponding deposit amount. The IC may issue comments within 30 calendar days of receiving the draft Facilities Study report. NSPI has 15 business days from receiving the comments to finalize the report and can reasonably extend that period if comments warrant doing so. NSPI must meet with the IC 10 business days after finalizing the Facilities Study final report.

Generator Interconnection Agreement

Once all studies are complete and an IC is ready to proceed, NSPI and the IC may execute a Standard Generation Interconnection Agreement (SGIA). In some cases, the IC may need to fully execute an Engineering and Procurement Agreement whereby the IC agrees to pay for costs arising from the interconnection costs (such as system upgrades). NSPI and the IC may negotiate or file an unexecuted GIA with the Board during the SIS stage.

2.2. Distribution Generator Interconnection Procedures Review

The general order of procedures a Distribution IC must undertake is as follows:[21]

- Distribution Interconnection Request
- Preliminary Assessment
- Distribution System Impact Study
- Standard Small Generator Interconnection Agreement (SSGIA)

Preliminary Assessment

The Preliminary Assessment identifies any potential adverse system impacts that would result from the IC facility's interconnection.[22] The study evaluates thermal limits, power quality issues (such as voltage, system load parameters), overlapping impacts of other ICs, and identification of upgrades. If both NSPI and the IC agree, the Preliminary Assessment can be deferred, and the Study Fee used towards the DSIS.

- **Fees**: NSPI charges a $750 Study Fee
- **Timeline**: NSPI has 30 calendar days to complete upon a valid interconnection request. NSPI must meet with the IC within 10 business days after completing the assessment.

[21] GIPs also provide for restudies and optional SISs.

[22] DGIP, 14.

When the Preliminary Assessment is complete, NSPI presents the DSIS agreement to the IC. Before commencing the DSIS, ICs must demonstrate they have achieved the following Progression Milestones 10 days prior to the study commencement: [23]

- Generator data
- Attachment A to Appendix 1[24]
- Point of interconnection
- Electrical equipment with rating and impedance info
- MW capacity
- Provision of one of the following
    - Contract for at least half of the generation in place;
    - NSPI approval of Net Energy Metering eligibility;
    - Local Distribution Company/Load-Serving Entity confirmation that capacity is required for demand, reliability, or Renewable Energy Standard requirements;
    - Board approval for Behind-the-Meter; or
    - Pilot program approval by Minister of Energy.

Distribution System Impact Study

The DSIS is a set of technical studies that evaluate the impact of the proposed interconnection on the reliability of and operation of the distribution system.[25] In the DSIS, NSPI will conduct a short-circuit analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary. Two major products of the DSIS are (1) a good-faith estimate of the cost (including overheads) of equipment, engineering, procurement, and construction work needed to implement the NSPI DGIP procedures; and (2) any operational conditions placed upon the generation facility.

- **Fees**: Non-binding good-faith cost estimate and timeframe for DSIS completion. The IC is on the hook for actual DSIS costs should they exceed NSPI's estimates.
- **Timeline**: With reasonable efforts,[26] the DSIS Draft is due 90 calendar days after the study commencement date. NSPI must meet with IC within 10 business days after the DSIS is complete. The IC can submit comments to NSPI within 15 calendar days, and NSPI must finalize the DSIS within 15 calendar days of receipt of the IC's comments or notice of intent to not file comments.

[23] DGIP, 17.

[24] Attachment A asks for generator information within Appendix 1, "the Distribution Generator Interconnection Request Form.

[25] DGIP, 18.

[26] Under the GIP's Reasonable Efforts construct, NSPI "shall make reasonable efforts to meet timeframes provided in these procedures. If NSPI cannot meet the required timeframe provided herein, it shall notify the Interconnection Customer and provide an estimated completion date with an explanation of the reason why additional time is required." Note that the "reasonable efforts" standard, derived from the original US FERC pro forma open access transmission tariff, has been modified by FERC with the issuance of its Order 2023 decision in July of 2023.

Standard Small Generator Interconnection Agreement

Once the DSIS is complete, the IC has 30 calendar days to execute the SSGIA and its corresponding appendices. Failure to do so in that time means the IC forfeits their interconnection request, which would result in removal from the interconnection queue. NSPI is required to review the SSGIA for completion within 15 days and flag any issues for the IC within this time. NSPI has 15 days to finalize the SSGIA upon the final submission. Once the SSGIA is fully executed, the IC will have satisfied all of the DGIP requirements.

3. Interconnection Procedure Substantive Issues

This section examines the issues addressed during the technical conferences and reflects on the stakeholder comments received. It informs the recommendations in the following Chapter. We review each issue in turn, identify and discuss concerns with the current procedures for that issue, and provide suggested resolutions as necessary, which are reflected in our recommendations section.

3.1. Interconnection Queue and Study Timing, OATT Compliance and Resource Sufficiency for Interconnection Studies

Overview and Queue Data Summary

Generation interconnection queue status for active requests[27] and data are available on NSPI's OASIS website. NSPI provides both an advanced stage interconnection queue for ICs at later stages of the GIPs,[28] as well as interconnection queues for distribution ICs and transmission ICs respectively.[29] The OASIS interconnection queue reports on the following data for each IC:

i. maximum summer and winter megawatt electrical output
ii. location by county
iii. station or transmission line or lines where the interconnection will be made
iv. projected in-service date
v. status of the interconnection request, including queue position
vi. type of interconnection service being requested
vii. availability of any studies related to the interconnection request
viii. date of the interconnection request
ix. type of generating facility to be constructed
x. an explanation of the reasons why IRs that do not result in a completed interconnection did not get completed
xi. type of interconnection customer (NSPI, or non-NSPI indicated as "N/A")

Appendix A contains the current (September 2023) active transmission system interconnection requests (36, totaling 4,648 MW) and active distribution system requests (35, totaling 94 MW). Notably, a sizable increase in transmission system interconnection requests for wind is seen just in 2023, and for solar PV on the distribution system, reflecting policy changes prescribing increases in renewable energy.

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[27] Withdrawn requests are not posted.

[28] Combined T/D Advanced State Queue: https://www.nspower.ca/docs/default-source/pdf-to-upload/nspi-combined-interconnection-request-queue(pdf).pdf?sfvrsn=d56d149_20.

[29] Transmission: https://www.nspower.ca/docs/default-source/pdf-to-upload/nspi-active-transmission-interconnection-requests(pdf).pdf?sfvrsn=17712f59_20. Distribution: https://www.nspower.ca/docs/default-source/pdf-to-upload/nspi-active-distribution-interconnection-requests(pdf).pdf?sfvrsn=bc46353_20.

Tables 3 and 4 below summarize the full set of active transmission system requests, by resource type and interconnection customer type (non-NSPI, or NSPI), for the metrics i) nameplate capacity (MW) and ii) number of interconnection requests. The table columns are ordered in sequence of the associated interconnection activity: validation of the interconnection request, followed by a feasibility study, then a system impact study, and a facilities study. Generation Interconnection Agreements (GIAs) follow after conclusion of the studies.

Table 5 below shows the full transmission queue for wind resources, between 2016 and 2023, with 2023 values for "date requested" provided on a monthly basis. This table illustrates the pattern of requests made for wind interconnection on the transmission grid by NSPI and non-NSPI entities before and after the new renewable energy requirements were put in place.

Tables 6 and 7 below contain a snapshot of the status of transmission and distribution interconnection requests advanced to the study stage from the initial request stage.[30] Advancing to the study stage requires meeting the milestones in the SGIPs and DGIPs. The table shows the status for both NSPI and non-NSPI interconnection applications that have advanced from the initial interconnection request (IR) stage.

[30] *Combined T/D Advanced Stage Interconnection Request Queue*, Nova Scotia Power Inc. (September 2023). Available at: https://www.nspower.ca/docs/default-source/pdf-to-upload/nspi-combined-interconnection-request-queue(pdf).pdf?sfvrsn=d56d149_18

Table 3. Transmission Interconnection Request Queue - Nameplate Winter MW by Resource Type, Customer (NSPI or non-NSPI), and Status of Studies – September 2023

Winter MW Nameplate	Non-NSPI Interconnection Customers							NSPI Interconnection Customer				Total All IC
Resource Type	IR Valid	FEAS In Progress	SIS in Progress	FAC in Progress	GIA in Progress	GIA Executed	Total	SIS in Progress	FAC in Progress	GIA Executed	Total	
Battery								50.0	100.0		150.0	150.0
Biomass										45.0	45.0	45.0
Tidal					5.5	7.6	13.1					13.1
Wind	1,460.5	1,794.0	566.1	323.6		108.9	4,253.1	186.9			186.9	4,440.0
Total MW	1,460.5	1,794.0	566.1	323.6	5.5	116.5	4,266.2	236.9	100.0	45.0	381.9	4,648.1

Source: NSPI OASIS, tabulation by Synapse.

Table 4. Transmission Interconnection Request Queue - Number of Interconnection Requests by Resource Type, Customer (NSPI or non-NSPI), and Status of Studies – September 2023

# of Interconn. Requests	Non-NSPI Interconnection Customers							NSPI Interconnection Customer				Total All IC
Resource Type	IR Valid	FEAS In Progress	SIS in Progress	FAC in Progress	GIA in Progress	GIA Executed	Total	SIS in Progress	FAC in Progress	GIA Executed	Total	
Battery								1	2		3	3
Biomass										1	1	1
Tidal					2	3	5					5
Wind	10	5	4	3		3	25	2			2	27
Total # of IRs	10	5	4	3	2	6	30	3	2	1	6	36

Source: NSPI OASIS, tabulation by Synapse.

Table 5. Wind Resource Interconnection Requests, Transmission Queue, 2023 (by month), and earlier periods (by year). MW and # of Requests, by Entity

	MW Winter Nameplate Capacity						# of Interconnection Requests					
	IR Valid	FEAS In Progress	SIS in Progress	FAC in Progress	GIA Executed	Total	IR Valid	FEAS In Progress	SIS in Progress	FAC in Progress	GIA Executed	Total
Non-NSPI Total All	**1,461**	**1,794**	**566**	**324**	**109**	**4,253**	**10**	**5**	**4**	**3**	**3**	**25**
'23 Total	1,461	1,794	340			**3,595**	10	5	1			**16**
Jan '23		340	340			680		1	1			2
May '23		1,380				1,380		3				3
June '23		74				74		1				1
July '23	210					210	2					2
August '23	1,144					1,144	7					7
September	106					106	1					1
'22			226	193		**420**			3	2		**5**
'21				130	36	**166**				1	1	**2**
'20					59	**59**					1	**1**
'16					14	**14**					1	**1**
NSPI Total			**187**			**187**			**2**			**2**
Total, NSPI and	**1,461**	**1,794**	**753**	**324**	**109**	**4,440**	**10**	**5**	**6**	**3**	**3**	**27**

Source: NSPI OASIS, tabulation by Synapse.

Table 6. Combined T/D Advanced Stage Interconnection Request Queue - Nameplate Winter MW by Resource Type, Customer (NSPI or non-NSPI), and Status of Studies – September 2023

Winter MW Nameplate	Non-NSPI Interconnection Customers							NSPI Interconnection Customer				Total All IC
Resource Type	SIS Milestones Met	SIS in Progress	SIS Com-plete	FAC in Progress	GIA in Progress	GIA Executed	Total	SIS in Progress	FAC in Progress	GIA Executed	Total	
Battery (T)								50.0	100.0		150.0	150.0
Biomass (T)										45.0	45.0	45.0
CHP (D)			5.6				5.6					5.6
Solar (D)	0.8	1.8				1.3	3.9					3.9
Tidal (T&D)					5.5	8.9	14.4					14.4
Wind (T)		566.1		323.6		108.9	998.6	186.9			186.9	1,185.5
Total MW	**0.8**	**567.9**	**5.6**	**323.6**	**5.5**	**119.1**	**1,022.4**	**236.9**	**100.0**	**45.0**	**381.9**	**1,404.4**

Table 7. Combined T/D Advanced Stage Interconnection Request Queue - Number of Interconnection Requests by Resource Type, Customer (NSPI or non-NSPI), and Status of Studies – September 2023

# of Interconn. Requests	Non-NSPI Interconnection Customers							NSPI Interconnection Customer				Total All IC
Resource Type	SIS Milestones Met	SIS in Progress	SIS Com-plete	FAC in Progress	GIA in Progress	GIA Executed	Total	SIS in Progress	FAC in Progress	GIA Executed	Total	
Battery (T)								1	2		3	3
Biomass (T)										1	1	1
CHP (D)			1				1					1
Solar (D)	2	3				4	9					9
Tidal (T&D)					2	5	7					7
Wind (T)		4		3		3	10	2			2	12
Total # of IRs	**2**	**7**	**1**	**3**	**2**	**12**	**27**	**3**	**2**	**1**	**6**	**33**

Tables 3 and 4 indicate the following for the transmission queue:

- Of the current total of 4,648 MW of requested interconnection capacity requests, most are for wind projects (27 of 36 total requests).
- Interconnection study activity is seen across all stages of the interconnection requests, with the largest level of activity in the earlier stages of request validation ("IR Valid")[31] and feasibility study (FEAS In Progress). Executed and in-progress generation interconnection requests are in place for both NSPI and non-NSPI entities, as are system impact studies (SIS).
- NSPI is the only entity with studies for battery energy storage.

Table 5 illustrates the following:

- All requests for wind interconnection in all years except for two requests in 2022 came from non-NSPI entities.
- Most (more than 4,000 MW of the total wind queue of 4,440 MW) of the interconnection requests for wind have been seen just during 2023 and 2022, reflecting the effect of the increase in renewable energy requirements and the beneficial economics of wind resources.
- System impact studies are in progress for 753 MW of new wind, and GIAs have been executed for another 109 MW. This 862 MW of wind consists of both rate base procured wind and other wind.
- More than 3,200 MW of wind resource interconnection requests are currently at the validation or feasibility study stage. This has important implications for the next stage of studies – system impact and facilities studies – that will be required prior to getting to GIAs for these resources.

Tables 6 and 7 illustrate the following:

- NSPI and non-NSPI requests are both advancing through the study stages, with the bulk of the requests associated with wind resources by non-NSPI requestors. More than 1,000 MW of wind resource requests have advanced to the SIS or facilities study stage, representing an important advance toward eventual GIAs, in support of the province's renewable energy needs.
- NSPI has two wind requests at the SIS study stage and is the only entity with any advanced stage battery studies (representing the Eastern Clean Energy Initiative).
- The solar requests are for distribution system interconnection (solely for non-NSPI entities), and the wind studies are all for interconnection on the transmission system.

[31] Section 3.3 of the SGIP describe the process to complete a valid interconnection request, and subsection 3.3.1 in particular contains the requirements, which include a deposit, a completed application, a planned point of interconnection, a one-line diagram of the planned facility interconnection and proof of ownership or interest in the land for the resource.

Interconnection Queue Study Timelines and Bottlenecks

Stakeholders commented that the current GIP requirements prevent interconnectors from moving through the study process without first obtaining a revenue contract from NSPI. Stakeholders commented that this can limit the participation of private-sector interconnectors in the deployment of new projects and may unfairly advantage utility-led projects in the interconnection process.[32] In NSPI's response to this, the company clarified that an executed contract for the sale of energy for at least 50 percent of the generation project capacity is one of five options available for a project to demonstrate that it is advanced enough to enter the System Impact Study process.[33] Other options for the project to demonstrate its readiness to enter the SIS process include confirmation of a long-term transmission service reservation, demonstration of approval by the NSUARB for expenditures necessary for the generation facility, demonstration by a load serving entity that the project's energy or capacity is needed, or if the IC is a retail supplier pursuant to the *Electricity Act*, S.N.S 2004, c25.[34] NSPI has indicated its acceptance of a further readiness criterium option for SGIP applicants to move to the system impact study stage is inclusion of behind-the-meter generation.[35]

The OASIS data does not provide timelines for the duration from request to final agreement (or any study stage in between). It shows the request date and the expected in-service date for the resource. As described in the SGIP, there are a number of steps required of interconnecting customers, including signing study agreements, prior to commencement of a reasonable efforts "study clock", which is 45 days for the feasibility study, and 120 days for the system impact study and also the facilities study.[36]

NSPI notes in its comments that "the average interconnection timelines are currently appropriate and manageable"[37] and references Table 1 from its May 3 comments, which indicated an average duration of 18 months for four completed transmission GIAs, and 9.7 months for completed distribution agreements.[38] NSPI also asserts that "the interconnection queue timelines in Nova Scotia are reasonable", noting that PJM is striving to reduce its average from 3 years to 18 months, and commenting on its (i.e., NSPI's) use of a "First Ready - First Served" approach since 2009.[39]

[32] NRStor Comments Following First Stakeholder Technical Conference, Comment 1.

[33] NSPI Responses to second submission of stakeholder comments and questions, pg. 2-3.

[34] SGIP, 43-44.

[35] NSPI August 10, 2023 Comments at page 4-5.

[36] The OATT and the SGIP allow for 45 calendar days to complete a feasibility study, after completion of a fully executed feasibility study agreement. If a restudy is required, it must be done within 45 calendar days. System impact studies must be completed within 120 days after the execution of the SIS agreement. Facilities studies must be completed within 120 days after receipt of the Interconnection SIS agreement.

[37] August 10 comments, page 10.

[38] Since those comments, one additional completed GIA is on the OASIS, for IR#597. Since its request date was May of 2021, the total duration for this GIA must be at least 24 months, thus raising the average.

[39] August 10 comments, page 10.

NSPI notes that the interconnection procedures contain provisions to allow for ICs to make changes to their facility, to cure deficiencies in information submittal, and to request additional studies. They also note some of the "outliers" contributing to the duration of some of the lengthier duration interconnection requests still in the queue.[40]

However, other than its commitment to "continue pursuing additional resources for key areas of the interconnection process..."[41] NSPI does not make specific suggestions for how it might ensure that all studies are completed within the "reasonable efforts" window allowed in the OATT.[42] However, NSPI does include comments in the August 10 submission that critically point out their efforts to:

> "…manage the IC queue as efficiently as possible while also working to augment resources when there are significant peaks in activity driven by external programs such as procurements of new renewable generation resources. These programs can strain the overall process due to the time and effort required to ramp up additional resources in response to the peaks".[43]

NSPI proceeds to show graphically the increase in feasibility and system impact studies that arose following three specific procurement effects – the Renewable Procurement Process, the Renewable Electricity Standard program (40%, prior to the recent increases), and the Rate Base Procurement Program.[44]

We address this further in the subsequent section below on "Sufficiency of Resources to Conduct Interconnection Studies".

OATT Compliance

A number of stakeholders have noted a concern with potential bias in interconnection study treatment between NSPI requests and non-NSPI interconnection requests.[45]

The open access transmission tariff contains as Attachment E "Standards of Conduct".[46] Attachment E describes the way in which NSPI's OATT must allow for non-discriminatory provision of transmission service, and the OATT codifies such practice through the provisions in this Attachment. Essentially, NSPI's transmission employees are not allowed to give preferential treatment in any tariff areas – such as interconnection application and transmission studies execution - pursuant to the Standards of

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[40] August 10 comments, pages 10-11.

[41] August 10 comments, page 10.

[42] As we note in the next section, this standard may be replaced with a stricter timeline adherence standard, if NSPI's OATT is to conform to the new FERC Order 2023.

[43] August 10 comments, page 11.

[44] August 10 comments, page 12.

[45] AREA, NRR, NRStor, and Energy Storage Canada.

[46] Nova Scotia Power Inc., Open Access Transmission Tariff, Attachment E, Standards of Conduct For the Provision of Wholesale and Renewable to Retail Electric Transmission Service. https://www.nspower.ca/docs/default-source/pdf-to-upload/oatt-appendix_e_standards-of-conduct.pdf?sfvrsn=2fc313ac_0.

Conduct of the tariff. NS Power also posts on its OASIS "OATT Standards of Conduct Compliance Information"[47] describing shared facilities, shared employees, employee transfers, potential merger partners, emergency deviations, prohibited disclosures, voluntary consent, exercises of discretion, and tariff discounts. This is a public posting of information that highlights the need for NSPI's transmission employees to follow the Standards of Conduct.

As noted in the Terms of Reference, "bias in treatment" refers to the extent to which NSPI follows the open access transmission tariff Standards of Conduct, which govern how transmission system employees of NSPI must interact with affiliate (i.e., Emera) and non-affiliate transmission customers. The two general rules listed in the Standards of Conduct and relevant to the potential for "bias in treatment":[48]

1. Transmission Function employees must function independently of Nova Scotia Power's Marketing and Sales employees, and from any employees of its Affiliates.
2. Transmission Function employees must treat all transmission customers, affiliated and non-affiliated, on a non-discriminatory basis, and must not operate its transmission system to preferentially benefit an Affiliate.

Under the OATT, NSPI may not exercise any bias or discrimination amongst ICs. The GIPs specify that the "Transmission Provider will use the same Reasonable Efforts in processing and analyzing Interconnection Requests from all Interconnection Customers, whether the Generating Facilities are owned by the Transmission Provider, its subsidiaries or Affiliates or others."[49]

NSPI has stated that the Nova Scotia Power System Operator (NSPSO), the arm of NSPI that provides transmission service,

> "…through adherence to its OATT Standards of Conduct, treats all interconnection customers on an equitable and non-discriminatory basis, and adheres to the processes and timelines of the GIP and DGIP for all ICs, including NS Power in its capacity as an IC".[50]

NSPI also states that

> "NS Power, in its capacity as an IC, has not experienced bias from NSPSO in its capacity as Transmission Provider, in favoring or providing special treatment for NS Power interconnection over those of other interconnection customers."[51]

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[47] https://www.nspower.ca/oasis/standards-of-conduct/standards-of-conduct-compliance-information

[48] NSPI OATT, Attachment E, page 128 of the tariff.

[49] SGIP, Section 2.2 Comparability, page 17.

[50] NSPI, May 3 Comments, Attachment 1, page 15.

[51] Ibid.

A review of the results of the transmission queuing process to date cannot determine affirmatively that no "bias" in treatment may have been exercised by NSPI/NSPSO. However, the Advanced Stage request queue does show that study outcomes have resulted in continuing movement, through the interconnection request queue process, for both NSPI and non-NSPI requestors. Commenters noted a concern with bias in treatment,[52] [53] [54] [55] but no specific indication was offered by any stakeholder, and NSPI's statement above asserts that bias is not present.

To our understanding, stakeholders are asking for additional discovery of NSPI/NSPSO or bilateral inquiry of non-NSPI interconnection customers to inform the detailed timelines associated with interconnection requests, to determine or establish potential bias in treatment. It is not clear how a more complete understanding of the specific sequence of information flows between interconnection customers and NSPSO, that may help to (or even clearly) establish the causes or drivers of delay, and those responsible, would inform whether, or not, bias was present. There is no clear evidence in the Advanced Stage queue status and date information, or in the comments, that bias is driving any of the timelines experienced by any of the interconnecting parties' requests.

In our opinion effort is needed to ensure increased study capability on the part of NSPI/NSPSO, to improve study timing – especially as the need for studies is likely to ramp up. Exploring in more detail potential violations of the Standards of Conduct comes with an opportunity cost that in our opinion may not confer net benefits for ratepayers.

[52] AREA, May 3 comments: "AREA believes that the release of historical queue data could be of assistance and would be relevant to this review. As only NS Power is involved in all of the various project interconnection meetings, it is otherwise difficult for ICs to determine whether any bias exists. AREA's concern under the topics of both OATT Compliance and System Modeling mostly relate to the broader issue of the role played by NS Power's Standards of Conduct, and the extent to which NS Power managers involved in wider system planning and commercial functions are also directly involved in overseeing employees responsible for the interconnection of IC facilities. Synapse refers throughout the report to "NSPI", without differentiating between the NSP System Operator and NS Power as a whole. AREA believes that this review, including topics involving NS Power's treatment of its own facilities' interconnections and NS Power system modeling, need to be considered through the lens of whether the current Standards of Conduct are sufficient, and if there are further mechanisms or best practices elsewhere that can be implemented to ensure the required functional separation between NS Power's transmission and wholesale merchant functions is properly maintained as part of the interconnection process."

[53] NRR, May 31 comments: "In the initial report, Synapse suggests that it needs more stakeholder input surrounding experience of bias. While NRR appreciates that specific experiences would provide clear issues for Synapse to consider, some intervenors who might usefully contribute may hesitate to do so for fear of being identified through the context of their experience. NRR recommends that Synapse factor this potential reticence into its assessment of the bias and self-interest issue. Analysis of this issue may require a focus on the structure of NS Power's protocols or implementation practicalities to identify potential issues, rather than specific intervenor experience. NRR stresses that it remains the responsibility of Synapse to make a meaningful finding on this issue, with or without further stakeholder input."

[54] Energy Storage Canada, May 31, questions and comments to Synapse: "The M10905 process may more effectively solicit the perspectives of third-party asset owners (including ESS) on this topic through bilateral communications between Synapse and third-party asset owners."

[55] NRStor, May 31 comments: "**OATT Compliance**. We believe the analysis of historical interconnection durations suggested by Synapse Energy Economics and stronger safeguards to eliminate bias in the process would be valuable."

FERC Order 2023

The US FERC issued a lengthy (almost 1,500 pages) Order 2023 on bulk system interconnection reform on July 28, 2023.[56] To the extent that NSPI continues to offer an open access transmission tariff in conformance with the FERC tariff structure, it may have to further update provisions of the NSPI OATT and the SGIP, beyond its currently-planned changes reflected in the August 10 Comments.[57] While FERC Order 2023 followed from a wide-ranging process that commenced in June 2022 with a notice of proposed rulemaking, and the Order itself includes extensive discussion and documentation of comments and the FERC's considerations, three key reforms to interconnection procedures stand out, and all are relevant to NSPI's interconnection procedures:

- **Implement a first-ready, first-served cluster study process**. This requires provision of a form of pre-application information, as the "feasibility study" was also eliminated as an element of the *pro forma* LGIP (large generation interconnection procedure). It requires provision of high-level "heat map" data illustrating the capacity available at potential points of interconnection. It requires all impact studies to be cluster studies.[58]

- **Increase the speed of interconnection queue processing**. This part of the Order eliminated the "reasonable efforts" standard and replaced it with delay penalties imposed on the transmission provider, along with incentives to reduce speculative interconnection requests, such as by using withdrawal penalties and imposing site control requirements.[59]

  FERC noted the following in instituting this change:

  > "There is every reason to believe that many of the factors contributing to significant interconnection queue backlogs and delay—including the rapidly changing resource mix, market forces, and emerging technologies—will persist. In response to those ongoing challenges, we find that it is just, reasonable, and not unduly discriminatory or preferential to eliminate the reasonable efforts standard and adopt a penalty structure that reasonably incentivizes transmission providers to ensure the timely processing of interconnection requests. We note that we are not finding that transmission providers have necessarily acted in bad faith or that their actions are the sole reason for the queue delays. Indeed, throughout this final rule, we adopt numerous reforms to appropriately incentivize interconnection customers to help reduce interconnection delays that may result from their conduct. Nevertheless, we find that the

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[56] US Federal Energy Regulatory Commission, Docket No. RM22-14-000, Order No. 2023, *Improvements to Generator Interconnection Procedures and Agreements,* July 28, 2023. https://www.ferc.gov/media/e-1-order-2023-rm22-14-000

[57] NSPI states "NSPSO will review and analyze FERC Order 2023 in detail and will work to apply any adjustments to its processes where and when applicable", and "NSPSO is aware of the recently published FERC Order 2023 which speaks to both a Study Delay Penalty as well as an Interconnection Application Withdrawal penalty; providing penalties for both the system operator and Interconnection Customer appears to be balanced position on this issue. NSPSO recommends further consideration of these provisions in the event NERC makes application for approval of these provisions with the NSUARB, or otherwise directed by the NSUARB." (August 10 comments, pages 13-14).

[58] FERC Order 2023, paragraphs 61-183.

[59] FERC Order 2023, paragraphs 962-1025.

> elimination of the reasonable efforts standard and the adoption of penalties for late studies are needed to create an incentive for transmission providers, which will help reduce interconnection delays and ensure that Commission-jurisdictional rates are just, reasonable, and not unduly discriminatory or preferential."[60]

This section of the FERC Order also included a brief section concerning "resource solicitation studies", or the option for a transmission provider to conduct a study concerning an RFP for resources, for example, as part of the means to increase the efficiency of the interconnection process. This could be applicable in Nova Scotia because NSPI's IRP indicates a steady need for renewable resources (generally, more than 1,200 MW of wind by 2030, plus some solar, in all runs), and the province has conducted separate resource solicitations (e.g., the Rate Based Procurement for wind). However, the FERC Order did not include this as a mandatory requirement for transmission providers, but it did note that such a study could be useful:

> "Notwithstanding our decision not to adopt the NOPR's resource solicitation proposal, we agree with commenters who note that, in certain regions, resource solicitation studies have the potential to reduce uncertainty, improve coordination, and make resource planning more efficient and cost effective. We acknowledge comments arguing that a resource solicitation study may be most effective if paired with a structure where the resources within the resource solicitation structure are granted their own queue position, as this provides the relevant resources and soliciting entity with actionable information and avoids the uncertainty and delay that may occur if a study is conducted only for informational purposes and the associated resources do not have a queue position that corresponds to the study assumptions."[61]

- **Incorporate Technological Advancements into the Interconnection Process**. This section requires the transmission provider to use the interconnection customers' operation assumptions for battery storage, among other reforms.[62] The FERC Order stated the following concerning this need for reform, at paragraph 1448 of the Order:

> "In the NOPR, the Commission stated that, as newer technologies with operating parameters that differ from traditional generation seek to interconnect, it is necessary for transmission providers to use assumptions that accurately reflect "the operating parameters of electric storage resources and co-located resources containing electric storage resources (including hybrid resources) so that the unique operating characteristics of such resources are taken into account during the generator interconnection process." The Commission stated that, because the pro forma LGIP includes only general requirements regarding the operating assumptions for generating facilities in interconnection studies, it was concerned that "electric storage resources, and co-located resources containing electric storage resources, may be studied under inappropriate operating assumptions that result in assigning unnecessary network upgrades and increased costs to interconnection customers." The Commission therefore preliminarily found

[60] FERC Order 2023, paragraph 966.

[61] FERC Order 2023, paragraph 132.

[62] FERC Order 2023, paragraphs 1324-1609.

> that "the lack of realistic operating assumptions used in interconnection studies for electric storage resources and co-located resources containing electric storage resources (including hybrid resources) can result in excessive and unnecessary network upgrades and may hinder the timely development of new generation, thereby stifling competition in the wholesale markets, and resulting in rates, terms, and conditions that are unjust and unreasonable." Further, the Commission preliminarily found that "the lack of appropriate operating assumptions used in interconnection studies may present an unduly discriminatory or preferential barrier to the interconnection of electric storage resources and co-located resources containing electric storage resources (including hybrid resources)."[63]

This portion of the FERC Order resonates for Nova Scotia interconnection requests that include battery energy storage, at either the transmission or the distribution system level. NSPI has indicated its intention to directly include battery energy storage resources as a separate type of resource, but it also needs to consider the intended operation of the resource when determining the resource capacity modeled in the interconnection studies.

In the next section we address the extent to which NSPI/NSPSO will need to have sufficient resources to conduct interconnection studies required to allow for increases in interconnecting renewable resources to meet Nova Scotia policies, and to help meet the spirit of the FERC Order 2023 reforms.

Sufficiency of Resources to Conduct Interconnection Studies

NSPI is aware that FERC Order 2023 is requiring a move by transmission providers from the "reasonable efforts" standard for interconnection studies completion to an incentive framework where transmission providers are penalized if studies are not completed within the tariff window.[64] If NSPI updates its reciprocal OATT status, which we assume will occur, NSPI must take this tariff change into account and should be better prepared to complete studies without delays or suffer non-ratepayer-recoverable penalties.

We strongly suggest NSPI proactively increase its interconnection study resources, as it seems it intends to do.[65]

As noted, NSPI has stated that it will review its resources to ensure study capability given the current need based on the queue and given the potential for continuing policy-based increases in renewables that will lead to an increasing number of interconnection requests. We suggest NSPI use, and NSUARB monitor through annual compliance filings, a set of proactive mechanisms to increase its capabilities to conduct interconnection studies at an accelerated pace that assumes interconnection applications for

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[63] FERC Order 2023, paragraph 1448.

[64] FERC Order 2023, paragraphs 962-964.

[65] August 10 Comments, at page 10, "NSPSO plans to continue pursuing additional resources for key areas of the interconnection process, to ensure timely studies for interconnection customers and timely transition through the queue for projects which advance to later stages of the interconnection process." Also at page 14.

renewable resources at a level seen in NSPI's recent IRP finding for the "No Atlantic Loop" scenarios.[66] The pace of wind interconnections required even under the competing "Atlantic Loop" scenarios is similar to the other scenarios, thus the interconnection study need is present regardless.

In order to meet these needs, and in order to potentially meet the new standard (penalties for delays) associated with the FERC reforms, NSPI should further address in its SGIP modifications filing other changes that may be required to meet both the province's need for expanded interconnection study capability, and NSPI/NSPSO's need to reform its OATT, where required, in accordance with the major tenets of the FERC Order 2023. Given the robustness of the IRP's findings for significant wind resource needs over (roughly) the next decade, it would be prudent for NSPI to plan for more than just infrequent procurement events (such as the Rate Base Procurement) and instead institute a steadier state of expanded study capability.

Suggested Issues Resolution

At this time, we do not recommend a directed inquiry into the extent to which NSPI/NSPSO has adhered to the OATT Standards of Conduct. Based on a review of the public interconnection queue data and based on the comments filed in this Matter, there is no direct indication that the processes or the results of the interconnection studies to date have reflected a bias in treatment between NSPI and non-NSPI interconnecting requestors.

NSPI can ensure improvements to study timing, or avoid any further increases to study timing, by laying out a detailed plan for increasing its interconnection study capabilities. We recommend NSPI include such a plan in its SGIP update filing, with clear indications of the costs and the mechanisms planned to ensure such capability increases.

Our recommendations also suggest that NSPI address relevant FERC Order 2023 issues by incorporating into its planned GIP updates (as noted in NSPI's May 3 filing at pages 3-4) any additional procedural terms to comply with the core tenets of Order 2023 likely to be applicable to NSPI. In particular, battery operation as indicated by the IC should dictate the nature of the study, rather than any NSPI-based assumptions about export levels during peak or non-peak periods.[67]

We also recommend that NSPI complete its study of FERC Order 2023 and include in its SGIP updates its specific approach to replace the "reasonable efforts" standard with one designed to always meet tariff timelines for study completion. To do this, NSPI must ensure sufficient staff or external resources to do interconnection studies, assuming a steady increase in need in order to interconnect on the order of 1,200-1,600 MW of renewable energy by 2030. NSPI must also address the FERC Order's elimination of

[66] A total of roughly 1,200 MW of additional wind resources, beyond the planned rate base procurements and roughly 200 MW of solar PV resources – most of which would likely be utility scale, requiring SGIP study – is needed by 2030.

[67] For example, NSPI has indicated that the SGIP can be amended to clarify the study metrics (for maximum facility output) to be used at a facility with a generation resource and a battery resource. NSPI notes that ICs will be required to demonstrate how the maximum facility output will not be exceeded (August 10 Comments, Appendix A, page 2).

the "feasibility study" aspect of the *pro forma* LGIP, and inclusion of dissemination of "heat map" interconnection capability in its reforms; and how its GIPs may be modified to address this. We note that the establishment of pre-application reporting in the Commercial Net Metering Program Matter and recommended in this case for non-CNMP connecting distribution resources, is at least somewhat analogous to FERC's requiring a heat map for use by large generation and battery resource interconnecting customers.

3.2. Commercial Net Metering Issues

Commercial net metering issues overlap broadly with the DGIP portion of this review because CNMP participants connect to NSPI's distribution system and can be subject to, and can impact, distribution system constraints that can also affect non-CNMP participants (i.e., those with generation or storage resources planned for interconnection "in front of meter", directly to distribution substations or feeders, such as (but not limited to) certain Community Solar PV resources).

The Board's Decision Letter in M10872[68] directed NSPI to implement modifications to the Commercial Net Metering Program (CNMP), some of which will directly affect the protocols for distribution interconnection. Other issues considered in the CNMP Matter 10872 will not have a direct bearing on the distribution protocols.[69] The Board also noted the ongoing review in this Matter 10905 of issues that could impact CNMP participants.

NSPI filed a compliance filing on July 18, 2023, containing updated CNMP terms and conditions, to clarify that battery storage nameplate capacity is not to be counted towards "nameplate capacity" concerning CNMP qualifications, and to clarify REC treatment. NSPI filed its Commercial Net Metering Program 30 Day Report on August 3, 2023.

That report, together with NSPI's August 10, 2023 comments in this Matter 10905 contained a recommendation to allow Class 2 resources to be fast-tracked if they met the IBR size classifications (less than 1 MW at the 25 kV level; less than 0.5 MW at the 12.5 kV level), but made no suggestion to otherwise modify service standards for distribution studies (DSIS) as currently contained in the DGIP, except for accommodating the battery energy storage systems without increasing the nameplate capacity of the CNMP facility.

As noted in the battery energy storage section below, the way in which NSPI assesses the impact of a battery storage facility connecting to the distribution system is critically important, and NSPI's language in the July 18 filing[70] did not clearly indicate a need to ensure that distribution studies carefully consider

[68] July 4, 2023.

[69] Including the mechanisms for banked energy credits, and the treatment of Renewable Energy Credits (RECs).

[70] Section 2.8 of the Commercial Net Metering Terms and Conditions (Attachment 2, page 3 of 7) of the July 18 filing states "However, the capacity of any battery storage device shall be considered for the purposes of study, design, and classification of interconnection service (i.e., Class 1/Class 2)".

the level of export (or plan for no export) of battery storage resources when considering interconnection costs.

The move towards fast-tracking IBR resources below the stated size thresholds represents a significant improvement in allowing more rapid development of smaller distribution-connected solar PV or battery energy resources.

Each of the CNMP issues relevant to the DGIP review is described below, and as necessary addressed in subsequent sections of this report:

- **Backlog of CNMP applications**. While NSPI did not agree that a backlog existed, NSPI did state that it will redistribute resources to prevent backlogs and ensure processes to address the issue. The processing of applications for the CNMP will be tracked and monitored in NSPI's annual reports. We note that analogous concerns have been raised[71] regarding the ability to study bulk transmission system interconnection requests, and we further note that NSPI has also indicated a commitment to ensure sufficient resources exist to timely conduct transmission system studies to help minimize interconnection delays that could be attributed to NSPI actions, in contrast to delays arising from interconnection customer actions. Our recommendations support a sustained increase in interconnection study capability on the part of NSPI/ NSPSO.
- **Pre-application Report**. NSPI is required to provide a pre-application report to requesting CNMP interconnection applicants. The report is designed to provide capacity and related technical information (e.g., availability of three-phase power, known constraints, other pre-existing data concerning the applicant's proposed point of interconnection of a type and size of generation or storage request). The report content is to be "broadly consistent" with the content suggested in the IREC 2019 Model Interconnection Procedures. NSPI provided the structure of this report in a filing to the NSUAB on September 1, 2023.[72]

  Some of the information available in the pre-application report may be seen in NSPI's current hosting capacity table data, but in general the report would contain more detailed information that would better allow prospective interconnection requestors to determine if they want to proceed to a full request. Updated hosting capacity maps and data could be used to provide the type of information IREC's procedures identify as valuable for providing information needed by distributed generation or battery resource developers. We recommend the pre-application reporting also be made available to non-CNMP applicants, for the same reason its availability provides value for the CNMP applicants: information to allow distributed generation projects to begin to assess the likelihood of a reasonable cost for interconnection at a particular location, informing project development prospects.
- **Annual reporting**. NSPI is required to provide annual reports on its CNMP activity. Analogous reporting requirements should be in place for NSPI for all distributed generation and battery

[71] Stakeholders have commented on the need for improved timing of interconnection studies.

[72] NSPI, M10872 – Commercial Net Metering Program Proposed Pre-Application Report and Process. September 1, 2023.

resource projects applying for interconnection to its distribution system, to allow for regulatory monitoring of the success of small-scale generation and storage project development.

- **Distribution system upgrade costs**. The Board agreed with NSPI's cost causation approach for the CNMP, pending further consideration in this Matter. We have reviewed and discussed the relevant issues during the second technical session, including material from NREL on alternatives to traditional approaches. Traditional cost causation approaches do not capture the potential benefit to customers other than the "triggering" (or first moving) distributed resource interconnecting customer. See the following section on cost allocation issues, and ways to move forward where potentially unreasonable interconnection cost liabilities are present, and where there may exist system benefits to spreading the costs over more than first mover. We recommend NSPI move beyond solely the conventional cost causation approach in recognition of the presence of other beneficiaries.
- **Class 1 / Class 2 size thresholds, service standards and fast tracking**. The CNMP Decision Letter accepted NSPI's current size classification, with Class 1 limited to facilities no greater than 100 kW nameplate capacity and noted that this Matter will address the threshold level itself. NSPI has proposed retaining the Class 2 threshold level of 100 kW, but fast tracking the interconnection process (with reduced timelines and reduced DSIS study deposits) for all inverter-based Class 2 resources less than or equal to 500 kW (at 12.5 kV connections) and less than or equal to 1 MW (at 25 kV connections). See the following section on threshold size and service standard issues.
- **Hosting capacity**. The Board accepted NSPI's approach and directed a filing of an initial hosting capacity analysis, which was done on August 3, 2023.[73] An updated hosting capacity analysis or map ("dynamic") is due to be filed in March 2024. See the following section on hosting capacity; we recommend a dynamic hosting capacity map that aims for a "coordinated" structure to enable full capture of the potential benefits to the system of distributed resource capabilities.
- **Group studies /cluster analyses**. The Board directed NSPI to implement study groupings in clusters by distribution zones. Going forward, this will be done for all DSISs, to "bridge the gap" until this Matter can establish formal methods for group studies. NSPI agrees to group studies for the DSISs and will update Section 4.2 of its DGIP. Distribution zones are defined as those zones with all feeders from one substation transformer.

The Board Decision Letter for the CNMP is a valuable benchmark to consider for DGIP considerations generally, to ensure consistent treatment across all distribution-connected resources while recognizing the differences between interconnecting customers with and without material on-site loads.[74]

Smaller (i.e., 1 MW and below) non-CNMP distribution interconnection requests may share similar attributes as CNMP projects, although the absence of a "host load" is a clear distinction that can affect

[73] https://www.nspower.ca/oasis/distribution-hosting-capacity-table.

[74] Non-CNMP connecting resources may have small service loads with minimal impact on the output profile of the connecting resource.

the impact of the connected resource on the distribution system. Pre-application reporting for non-CNMP sites by NSPI will help customers gauge whether to submit full applications for interconnection. Fast-tracking for smaller IBR resources should use the same guidelines as those that impact CNMP interconnections.

Larger distribution projects (i.e., greater than the 1 MW threshold for CNMP) that are behind-the-meter may have similar impacts as smaller CNMP projects, depending on the size of the host load.

Lastly, larger stand-alone projects connecting to the distribution system may cause the greatest upgrade cost need, depending on if or how battery storage resources co-located with generation supply are sized and configured.

The recommendations section of this report contains our suggestions for distribution interconnection procedures for non-CNMP participants.

3.3. Energy Storage Considerations

Numerous stakeholders have commented on the need for updating the protocols to address the differences between battery energy storage system (BESS) resources and generic generation resources, and how those differences affect or should affect the assumptions used when analyzing interconnection requirements for battery systems.[75] NSPI has acknowledged these concerns and has indicated its willingness to update the GIPs and associated documents to address them.[76] BESS resources generally are or can be visible to NSPI, and as necessary controllable, and can both absorb energy (acting as a load) or deliver energy (acting as a generator).

While this review is not an attempt to gauge the overall quantitative benefits or values that BESS resources can bring to the system, it is critical that the interconnection procedure (for transmission and for distribution connected resources) not impose excessive interconnection costs on battery storage connecting customers if those resources' planned operations do not lead to unreliable system conditions and if interconnection agreement protections are in place to ensure those outcomes.

NSPI's interconnection protocols (leading to interconnection agreements) should explicitly include planned operations for BESS resources, and the interconnection agreements should support the outcomes of studies that reflect the planned operating protocols for BESS resources.

[75] Energy Storage Canada, NStor, RIMOT.

[76] NSPI, May 3, 2023, Comments on Synapse's Initial Technical Report. NSPI indicates potential amendments to GIP Sections 2.1, 7.2, 8.1, DGIP Section 2.1, and in generation interconnection agreements for large (GIA) and small scale (SSGIA) generation. August 10 Comments, page 4, 13, and Attachment A pages 2-3 (which specifically notes at page 2 "Where an energy storage system (ESS) is utilized with the generating facility, the interconnection request shall be evaluated using the stated MW output (given in the IC request) to the Distribution System" and "…NSPSO believes the SGIP and DGIP may be reasonably amended to address concerns related to Energy Storage Solutions. In particular, introducing amendments which clarify whether the larger of nameplate info from the generator or the generator nameplate plus EEE along with customer defined maximum facility output, apply as study metrics. Additionally, the customer will be required to demonstrate how the maximum stated facility output will not be exceeded."

NSPI revised its DGIPs in 2019 to reflect the influx of behind-the-meter (BTM) resources. Yet, these protocols do not specifically mention energy storage systems. IREC recommends developing a dedicated interconnection procedure pathway to recognize the emergence of energy storage systems by explicitly naming them in procedures and tariffs.[77]

Energy storage as a resource both supplies and absorbs energy, and generally is fully controllable in its operation. Interconnection protocols should directly consider (e.g., through application of appropriate study metrics) the different and generally beneficial nature of energy storage resources.

Appendix D contains the newly released 2023 Model Interconnection Procedures from IREC. It contains and references "best practices" information for battery energy storage interconnection from IREC's March 2022 toolkit[78].

IREC's storage toolkit guidance document notes the following in its Executive Summary:

> Storage is a foundational tool in [the energy] transition. As renewable generation grows, storage will become an increasingly important asset for the energy management services it provides.
>
> For example, when paired with solar, storage can provide more control over the timing and amount of energy imported from and exported to the electric grid and can support the integration of renewables through several means, including by providing frequency regulation. Utility-scale storage can provide better resource management in states with high wind and solar deployment by mitigating the intermittency of renewable generation. And [behind-the-meter] storage can serve as a resilience resource, reduce energy costs for customers, and reduce the need for infrastructure investments necessary to serve peak demand.
>
> These capabilities present both opportunities and challenges for storage interconnection. In order to ensure the continued safe and reliable operation of the grid, utilities must be able to trust that storage will operate as described in interconnection agreements, which allows utilities to anticipate and respond to any potential grid impacts. At the same time, interconnection customers must have access to a fair, efficient, and cost-effective interconnection process that gives them maximum freedom to interconnect their storage assets in a manner that meets their needs (e.g., having the flexibility to respond to price signals).

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[77] Interstate Renewable Energy Council. *Building a Technically Reliable Interconnection Evolution for Storage (BATRIES): Toolkit & Guidance for the Interconnection of Energy Storage & Solar-Plus Storage (March 2022) available at* https://irecusa.org/programs/batries-storage-interconnection/*; and, Priority Considerations for Interconnection Standards: A Quick Reference Guide for Utility Regulators* (August 2017), available at: https://irecusa.org/wp-content/uploads/2021/07/IREC-Priority-Considerations-for-Interconnection-Standards-2017-FINAL.pdf.

[78] IREC, Toolkit and Guidance for the Interconnection of Energy Storage and Solar + Storage, March 2022. Available at https://energystorageinterconnection.org/resources/batries-toolkit/. The newly released Model Interconnection Procedures 2023 also reflect or contain this information.

> Most states' existing DER interconnection procedures are not designed with storage in mind, which can create unintended time, cost, and technical barriers to storage integration. As one example, most interconnection rules either permit or require utilities to evaluate the impacts of storage on the grid with the assumption that storage systems will export their full nameplate capacity at all times. In reality, this assumption is extreme for several reasons and doesn't reflect how storage is typically operated, thus creating an unnecessary—but solvable—barrier to storage interconnection.
>
> In addition, interconnection procedures that aren't tailored to serve a jurisdiction's DER market conditions—such as when the speed of DER deployment outpaces the grid's existing hosting capacity or utilities' ability to process applications—can lead to serious queue backlogs or high grid upgrade fees that become barriers to interconnection.

Several commenters questioned whether existing interconnection processes and requirements are sufficient for non-generation technologies, such as battery energy storage systems, which are not specifically in the GIP requirements. NSPI responded that energy storage systems can function as generation sources and should be studied under the GIP when they are intended to provide peak shifting or in other configurations, and noted GIP already accommodates the evaluation of BESS project notwithstanding the specific reference to BESS in the GIP and DGIP.

Our recommendations include specific incorporation of including the distinctions between battery energy storage and generation resources in the SGIP and DGIP document, which NSPI is directly addressing.

3.4. Fast Tracking for Interconnection Studies and Threshold Capacity Size for Class 2 Distributed Resources

Section 2.5 of the SGIPs currently states that NSPI may at its discretion fast-track small generating facilities. The fast-tracking procedures are similar to IREC's model procedures, which give the utility the option to waive the Facilities Study if there are no substantial system impacts from interconnecting. NSPI may fast-track ICs by foregoing the Feasibility Study, combining the SIS and Facility Study, removing the requirement to coordinate with other affected systems, and modifying the SIS to omit a stability analysis. The SGIP gives NSPI broad discretion to determine applicability of feasibility, facilities, and SIS studies and currently does not specify what governs this decision-making or what would trigger such a waiver and privilege. Fast-tracking can lower the fee for certain applications, saving both the IC and utility time and costs.[79] NSPI's DGIPs do not currently directly address fast tracking but as noted below, NSPI has identified required changes for fast tracking.[80]

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[79] *Priority Considerations for Interconnection Standards: A Quick Reference Guide for Utility Regulators*, Interstate Renewable Energy Council (August 2017). Available at: https://irecusa.org/wp-content/uploads/2021/07/IREC-Priority-Considerations-for-Interconnection-Standards-2017-FINAL.pdf.

[80] August 3 Commercial Net Metering Program 30 Day Report, M10872, page 6. August 10 Comments, pages 17-18.

Stakeholders identified the size threshold for Class 2 distributed resources (vs. smaller Class 1 distributed resources) and the related potential for fast tracking the interconnection study process for smaller or lower-impacting generation or storage resources as a critically important issue to support market development of smaller renewable resources.

NSPI has indicated in this Matter its intention to fast track the study process for distribution connected resources that are inverter-based (solar PV and battery resources are both inverter-based) if they are less than 500 kW for 12.5 kV level interconnections, and if they are less than 1 MW for connection to the higher voltage parts of the distribution system (at 25 kV).[81]

The practical effect of this modification is a significant increase in the threshold size at which ICs can expect faster studies, see reduced study deposit fees, and increase the expectations for a faster overall interconnection process for small renewables and battery energy storage resources. However, NSPI has not indicated it will increase the 100 kW threshold itself, and that while Class 2 resources that meet the IBR criteria will have a faster tracked process, and the DSIS would likely be quicker – the study deposit is lowered from $10,000 to $2,500 – it is still considered class 2 and NSPI retains the option to always perform a DSIS. NSPI indicated during the second technical conference an openness to continue looking at the thresholds and impacts to the grid. Beyond NSPI's fast tracking of resources that meet the IBR criteria, we recommend NSPI continue to review the Class 2 threshold levels and update those thresholds (i.e., increase the level at which a resource is considered Class 2, or supplement the IBR criteria to increase the IBR threshold) where warranted if grid impacts indicate that can be done reliably.

NSPI has indicated that all Class 1 (i.e., less than 100 kW) resources are essentially fast tracked.[82] Since the second technical conference in July, NSPI has submitted its Commercial Net Metering 30 Day Report which includes plans to allow fast tracking for CNMP inverter-based resources at or below 500 kW (on the 12.5 kV system) and at or below 1 MW (on the larger 25 kV nominal distribution system). That fast tracking will substantially improve DSIS study timelines (from 90 days to 30 days), will lower study deposits (from $10,000 to $2,500) and will initiate DSISs within 10 business days of ICs meeting all the application milestones and allow projects to enter the advanced stage queue.[83] NSPI also notes that it is reviewing technical requirements for Class 2 resources to "simplify the interconnection of these devices." Synapse recommendations include an NSPI filing to provide a clear indication of expected changes to this document and filing of an updated Interconnection Requirements.[84]

Synapse assumes that the fast-tracking processes being implemented for the CNMP will also apply to non-CNMP distribution applications of similar scale, as noted in the recommendations in this report.

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[81] August 10 Comments, pages 17-18.

[82] May 3 Comments, Attachment 1, page 5.

[83] August 3 Commercial Net Metering Program 30 Day Report, M10872, pages 6-7.

[84] The current version of this document is August 14, 2020. Our initial review indicates that it excludes any specific distinction between battery and generation resources. An updated version must specifically include distinguishing between generating and battery storage resources in this document, in all relevant areas of the document.

NSPSO had indicated during the second technical conference that non-IBR resources greater than 100 kW continue to require study, and it appears that that remains NSPI's underlying rationale for not modifying the formal Class 2 threshold, but instead instituting the fast tracking for IBR resources. Since most of the small renewable resources expected on NS Power's system will be IBR resources, Synapse does not see a reason at this time to suggest modifications to NSPI's plan to maintain the Class 2 threshold at 100 kW for distribution system interconnection requests but as noted recommends NSPI continue to examine this threshold level and further consider the value of increasing the level, if technically appropriate.

For transmission connected or transmission system impactive resources, NSPI has indicated its intention to i) eliminate re-study deposits, ii) lower the fee structure and improve the study timelines, and iii) combine the facilities and system impact study - for interconnection applications for smaller (less than or equal to 10 MW) resources interconnecting to the transmission system.[85] This creation of a lower capacity threshold for smaller transmission system or transmission system effecting resources seems a promising modification to allow for faster and lower cost interconnecting of Community Solar scale solar PV resources. Synapse recommendations include NSPI reporting on how this change affects ICs over the next few years as Community Solar interconnections increase.

3.5. Hosting Capacity

Overview

Stakeholders support issuance of hosting capacity information by NSPI. SWEB noted the importance of accurate, reliable and informative hosting capacity information in order for it to be effective. NRStor noted that access to high quality information about hosting capacity and local grid conditions will enable more strategic and cost-effective projects to be deployed across the province. While many comments were focused on the capacity size thresholds and study timelines for distributed resources, the presence of a useful, up-to-date hosting capacity map or analysis, can provide critical information to support development of both solar PV and battery energy storage resources at distribution system scale.

Hosting capacity is a measure of the amount of headroom available on the distribution system to allow for installation of solar PV supply, or potentially other distributed resources such as battery energy storage (supply or load).

Synapse defined hosting capacity in a report completed for the Minnesota Department of Commerce, Division of Energy Resources, in September of 2021:[86]

> Hosting capacity refers to the amount of DERs that can be accommodated on the distribution system on a given circuit without adversely impacting power quality or reliability and without

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[85] May 3 Comments, Attachment 1, page 6. August 10 Comments, pages 7-9.

[86] Hosting Capacity Analysis and Distribution Grid Data Security, at https://www.synapse-energy.com/sites/default/files/Hosting_Capacity_Analysis_and_Distribution_Grid_Data_Security_21-016.pdf. Page 4.

> requiring infrastructure upgrades.[87] Hosting Capacity Analysis is a useful tool for assessing the locational value of DERs at increasing levels of penetration on the grid. Hosting capacity maps, a visual representation of an HCA, can be used to transparently share information between regulators, developers, electric customers, and utilities. This results in more efficient and economical DER deployment on the grid.[88]
>
> There are three primary applications, or use cases, for an HCA: (1) to support market-driven DER deployment by enabling developers to identify technically suitable and potentially lower-cost interconnection locations; (2) to assist with streamlining DER interconnections by improving or automating parts of the technical screening process; and (3) to enable more robust, long-term distribution system planning, which provides visibility into how much DER the grid can host in future years by identifying potential system constraints and proactive upgrades.

For the purposes of this Matter, the first two use cases cited above for hosting capacity analysis are directly relevant as interconnection issues, and the third use case should be considered in other Nova Scotia matters associated with NSPI's distribution planning, and to consider when reviewing NSPI's March 2024 dynamic hosting capacity analysis filing.

NREL defines hosting capacity as follows:[89]

> Hosting capacity is the amount of DPV [distributed photovoltaic] that can be added to the distribution system before control changes or system upgrades are required to safely and reliably integrate additional DPV. *Hosting capacity does not represent a hard limit on the amount of DPV that can be added to the distribution system*. As upgrades are implemented, the hosting capacity of the system increases. The analysis of these sequential increases in hosting capacity and their related costs are at the core of NREL's approach.
>
> Hosting capacity is highly relational, dependent on a number of factors, including:
>
> - The characteristics of the DPV system, such as whether advanced inverter settings are utilized, the system size, and where it is located on the circuit
> - The location and time-varying behavior of all distributed energy resources on the circuit, such as distributed storage
> - The existing equipment on a circuit at any given time, which will evolve over time depending on investments made by utilities and DPV owners or developers
> - The distribution planning practices used by the utility—especially how they determine when upgrades or other mitigations are required.

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[87] Electric Power Research Institute (EPRI). 2020. Defining a Roadmap for Integrating Hosting Capacity in the Interconnection Process. p. 3. https://www.epri.com/research/programs/108271/results/3002020010.

[88] Stanfield, Sky and Stephanie Safdi. 2017. Optimizing the Grid: A Regulator's Guide to Hosting Capacity Analyses for Distributed Energy Resources. Interstate Renewable Energy Council (IREC). p. 1. https://irecusa.org/wpcontent/uploads/2017/12/Optimizing-the-Grid_121517_FINAL.pdf.

[89] https://www.nrel.gov/solar/market-research-analysis/advanced-hosting-capacity-analysis.html

IREC defines hosting capacity analysis as follows:[90]

> Hosting capacity analyses are an analytical tool that can help states and utilities plan for and build a cleaner electric grid that optimizes customer-driven distributed energy resources (DERs), such as rooftop solar, energy storage, or electric vehicle charging stations.
>
> They provide a snapshot in time of the conditions on a utility's distribution grid that reflect its ability to "host" additional DERs at specific locations on the grid—without the need for costly grid upgrades or lengthy interconnection studies. They are often displayed in the form of maps with supporting datasets.

NREL further defines three approaches to hosting capacity analysis:[91]

- Snapshot (traditional firm interconnection approach). This uses "worst case" static snapshots of the system. It is the approach used to develop the first versions of hosting capacity maps, such as seen in California in the initial versions of public maps depicting hosting capacity.[92]
- Uncoordinated Dynamic (interconnection using autonomous advanced inverter functionalities without communication to the utility). This approach allows for the capture of additional inverter functionality, such as volt-var control, but is not coordinated with the utility.
- Coordinated Dynamic (flexible interconnection). Curtailment risk is accepted by the PV developer as an alternative to paying for traditional distribution upgrades, and inverters' communication capabilities are utilized and coordinated with the utility. New York's "flexible interconnection capacity solution"[93] is an example, and other utilities are actively exploring this modality.[94]

NSPI has indicated its current preference for the traditional "Snapshot Hosting Capacity" interconnection approach, pending further investigation of other models or methods.[95]

In the Commercial Net Metering Program Matter 10872 the Board directed NSPI to publish a draft analysis of hosting capacity and update such analysis within 8 months.[96] NSPI published a table of

90 https://irecusa.org/our-work/hosting-capacity-analysis/

91 https://www.nrel.gov/solar/market-research-analysis/advanced-hosting-capacity-analysis.html.

92 Circa 2017-2019. For example, see this 2017 Utility Dive article. https://www.utilitydive.com/news/how-californias-utilities-are-mapping-their-grids-for-distributed-resource/436899/

93 https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B6D9EFACC-17FF-4695-9768-B89FA754EBA9%7D#:~:text=The%20Flexible%20Interconnect%20Capacity%20Solution,thus%20providing%20a%20less%20expensive%2C.

94 For example, Eversource in Massachusetts, and with service territories in Connecticut and New Hampshire also. https://www.mass.gov/doc/june-8-2023-tsrg-meeting-38-attachment-interconnection-automation-overview-external/download

95 NSPI May 3 comments, Attachment 1, page 18.

96 M10872, Board Decision Letter, July 4, 2023. Page 4.

distribution hosting capacity by feeder on its OASIS site on August 3, 2023.[97] The hosting capacity table is described by NSPI on the website:

> The following table provides estimates for solar (PV) generation hosting capacity by distribution feeder. The actual hosting capacity will be determined during the Preliminary Assessment stage of the DGIP. Distribution Zone PV Hosting Capacity is the estimated amount of additional PV generation that could be integrated within the Distribution Zone without causing transmission system impacts. Feeder PV Hosting Capacity is limited to the available Distribution Zone PV Hosting Capacity or the design limit of the distribution feeder less any installed (or advance stage) generation on the feeder.

The data includes feeder and distribution hosting capacity for 556 feeders, within 140 distribution zones. Table 8 summarizes the hosting capacity data by county.

Table 8. Hosting Capacity, MW, by County

County	Feeder Total MW	Distr. Zone Total MW	# of Feeders	Average MW per Feeder
Annapolis	42	46	17	2.5
Antigonish	16	101	22	0.7
Cape Breton	224	254	59	3.8
Colchester	90	125	27	3.3
Cumberland	130	161	34	3.8
Digby	40	45	16	2.5
Guysborough	10	13	10	1.0
Halifax	1,084	1,340	146	7.4
Hants	52	81	17	3.1
Inverness	24	45	29	0.8
Kings	122	122	28	4.3
Lunenburg	71	101	34	2.1
Pictou	105	266	51	2.1
Queens	23	23	13	1.8
Richmond	14	31	13	1.1
Shelburne	30	30	15	2.0
Victoria	19	31	11	1.7
Yarmouth	43	43	14	3.1
Total	**2,139**	**2,858**	**556**	3.8

Source: NSPI. Average MW per Feeder computed by Synapse from table data.

The capability (or hosting capacity) of the distribution system to sustain new distributed generation capacity before an upgrade is necessary can be expressed at the feeder or the distribution zone level. As

[97] https://www.nspower.ca/oasis/distribution-hosting-capacity-table

seen, NSPI has provided basic data at both feeder and distribution zone levels in their published Distribution Hosting Capacity Table. Hosting capacity information serves a valuable role in providing information to the marketplace concerning the identification of the locations across the distribution grid where the most headroom exists to install new DERs.

In theory, hosting capacity could be further segmented at the feeder level, accounting for the feeders' detailed circuitry attributes, load distribution along the feeder and potential feeder equipment such as reclosers, voltage regulators, capacitors, and control systems for such equipment. Interconnection queues and required system upgrades can substantially impact the total cost and timeline of project development (up to weeks of delays and tens of thousands of dollars) and place the viability of a distributed generation project overall in jeopardy.[98]

As noted, in the CNMP Decision Letter the Board approved the establishment of Pre-application reporting by NSPI. Pre-application reports will provide, on an individualized basis, the type of information that could be available more systematically in a hosting capacity map / analysis. In addition to Pre-Application Reports, some utilities are now publishing publicly available maps of their distribution systems, which provide basic information such as line voltage and capacity at specific points on the systems, or even offer actual calculated hosting capacity for each node.

The Board directed NSPI to consider a dynamic hosting capacity map in this matter. A dynamic hosting capacity map would allow for frequent updating as feeder level hosting capacity changes given ongoing distributed generation installations, load changes or other feeder modifications. NSPI has indicated in its Comments that it is "amenable to the development of a solution which is consistent with recommendations within the IREC model". NSPI will publish an interactive hosting capacity map by March of 2024, consistent with the Board's Letter Decision.

The Flexible Interconnection strategies associated with the "Coordinated Dynamic" approach noted above should be considered by NSPI when it develops its filing for its hosting capacity analysis update. NSPI should also ensure that any questions raised by interconnection customers concerning interpretations of the data in the current hosting capacity table be readily answered.

IREC's information on hosting capacity is contained in their September 2021 publication "Key Decisions for Hosting Capacity Analysis".[99] The report provides context across all of the dimensions of hosting capacity information, including what a hosting capacity analysis consists of, sample data, the nature of

[98] A study of five U.S. states found that 50 percent of small commercial net metering projects took 20 days or more to receive approval on their application; of these, the median time for completion was 39 days. See: Ardani, K., Davidson, C., Margolis, R., & Nobler, E. (2015). A State-Level Comparison of Processes and Timelines for Interconnection in the United States. National Renewable Energy Laboratory (NREL). Retrieved at: https://www.nrel.gov/docs/fy15osti/63556.pdf; Bird, L. Flores, F, Volpi, C., & Ardani, K. (2018). Review of Interconnection Practices and Costs in the Western States. NREL. Retrieved at: https://www.nrel.gov/docs/fy18osti/71232.pdf.

[99] https://irecusa.org/resources/key-decisions-for-hosting-capacity-analyses/.

phasing in hosting capacity analysis information, and the granularity of data contained in hosting capacity maps.

Figure 1 below shows example data for hosting capacity analysis from IREC's report. It serves as a starting point for the more detailed level of granularity that may be provided in NSPI's update to its newly published hosting capacity data table. Some of the information in Figure 1 is already available in NSPI's August 2023 posted hosting capacity table, such as feeder voltage, feeder and distribution zone hosting capacity, and at least implied information (in the naming conventions) on substations and substation transformers.

Figure 1. Example Data for Hosting Capacity Analysis or Results Reporting

<table>
<tr><td colspan="2">

Examples of the many data requirements for hosting capacity reporting

- Total capacity of substation/area bus or bank and circuit likely to serve proposed site
- Aggregate existing generating capacity interconnected to the substation/area bus or bank and circuit likely to serve proposedsite
- Aggregate queued generating capacity proposing to interconnect to the substation/area bus or bank and circuit likely to serve proposed site
- Available capacity of substation/area bus or bank and circuit likely to serve proposed site
- Whether the proposed generating facility is located on an area, spot, or radial network
- Substation nominal distribution voltage or transmission nominal voltage if applicable
- Nominal distribution circuit voltage at the proposed site
- Approximate circuit distance between the proposed site and the substation
- Load profile showing 8760 hours, by substation and transformer, when available
- Relevant line section(s) actual or estimated peak load and minimum load data, when available
- Number and rating of protective devices, and number and type of voltage regulating devices, between the proposed site and the substation/area
- Whether or not three-phase power is available at the site and/or distance from three-phase service
- Limiting conductor rating from proposed Point of Interconnection to distribution substation
- Based on proposed Point of Interconnection, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks
- Any other information the utility deems relevant to the applicant

</td></tr>
<tr><td>

Feeder-Specific Data

- Feeder name or identification number
- Substation the feeder connects to
- Feeder voltage
- Number of phases
- Substation transformer the feeder connects to
- Feeder type: radial, network, spot, mesh, etc.
- Feeder length
- Feeder conductor size and impedance
- Service transformer rating
- Service transformer daytime minimum load
- Existing generation (weekly refresh is desired)
- Queued generation (weekly refresh is desired)
- Total generation (weekly refresh is desired)
- 8760 load profile
- Percentage of residential, commercial, industrial customers
- Currently scheduled upgrades
- Federal or state jurisdiction
- Known transmission constraint requires study
- Notes of other relevant information to guide interconnection applicants

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Substation-Specific Data

- Name or identification number
- Voltages
- Substation transformer's Nameplate Rating
- Existing generation (weekly refresh is desired)
- Queued generation (weekly refresh is desired)
- Total generation (weekly refresh is desired)
- Load profile showing 8760 hours, by substation and transformer
- Percentage of residential, commercial, industrial customers
- Currently scheduled upgrades
- Has protection and/or regulation been upgraded for reverse flow? (yes/no)
- Number of substation transformers and whether a bus-tie exists
- Known transmission constraint requires study
- Notes of any other relevant information to help guide interconnection applicants, including electrical restrictions, known constraints, etc.

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</table>

Hosting Capacity Efforts in Other Jurisdictions

Institutions such as the National Renewable Energy Laboratory (NREL) in the United States are developing tools and resources that utilities can use to identify, measure, and report hosting capacity. California's Sacramento Municipal Utility District (SMUD) partnered with NREL to develop an automated hosting capacity analysis that can handle multiple interconnection application requests across the SMUD distribution system, thereby reducing the utility's workload (and costs) for the initial screen of remaining hosting capacity on an individual circuit. NREL stated that this tool can be scaled and applied to other jurisdictions.

Under California's Rule 21, ICs can pay a separate fee to obtain additional packages of information from the utility. This includes information about minimum load, existing upstream protection devices, available fault current at the proposed point of interconnection, transformer data, and primary and secondary services characteristics. This information can help ICs design better projects from the start with fewer surprises later in the process.[100]

The New Mexico Public Regulation Commission adopted a November 2022 order requiring that distribution utilities use a multiple-screening process for smaller (≤25 kW) projects to determine whether their interconnection on any particular circuit would exceed 100 percent of minimum load instead of the traditionally used 15 percent of peak load screening to determine whether any circuit could absorb additional DER interconnections without needing system upgrades.[101] The New Mexico approach, championed by IREC, is expected to reduce the volume of redundant interconnection requests and also reduce the processing required for smaller (≤25 kW) projects that a distribution utility would need to evaluate.

Other jurisdictions are passing hosting capacity reporting requirements as grid planners, project developers, and policymakers collectively recognize their important role in facilitating efficient interconnection.[102] To the extent that more real-time detailed information on the hosting capacity of a circuit is shared with developers and discourages multiple or redundant interconnection requests, that could reduce the volume of interconnection requests, expedite the average interconnection process duration, lower interconnection costs, and ultimately lower the cost burden on ratepayers.

Many jurisdictions phased in hosting capacity data-sharing requirements in some way because of the time and complexity associated with aggregating and maintaining the underlying data required, shown in Figure 1 above.[103] Some phase in the implementation to more quickly publish basic distribution system data or to allow more hosting capacity granularity to be added over time.

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[100] *Model Interconnection Procedures: 2019 Edition*, Interstate Renewable Energy Council (2019), 4. Available at: https://irecusa.org/wp-content/uploads/2021/07/IREC-model-interconnection-procedures-2019_100319.pdf.

[101] Interstate Renewable Energy Council, "How New Mexico's New Interconnection Rules Position It as a Clean Energy Leader." (December 7, 2022), https://irecusa.org/blog/regulatory-engagement/how-new-mexicos-new-interconnection-rules-position-it-as-a-clean-energy-leader/.

[102] *Model Interconnection Procedures: 2019 Edition*, Interstate Renewable Energy Council (2019), 4. Available at: https://irecusa.org/wp-content/uploads/2021/07/IREC-model-interconnection-procedures-2019_100319.pdf; N.J.A.C. 14:8-5.11(a) requires each EDC, by January 1, 2024, to file a tariff that includes "a common Hosting capacity mapping process to aid Customer-generators. Hosting capacity maps shall indicate locations on the distribution [grid] with spare capacity and which locations are likely to require additional upgrades."

[103] Sky Stanfield, Yochi Zakai, Matthew McKerley. *Key Decisions for Hosting Capacity Analyses*. IREC (Sept. 2021), https://irecusa.org/resources/key-decisions-for-hosting-capacity-analyses, page 11 Many jurisdictions phased in their hosting capacity rollout in some way because of the time and complexity associated with implementing the first HCA. Some

Synapse recommends that NSPI works towards development of a hosting capacity analysis with "coordinated dynamic" attributes, recognizing that existing and emerging distributed resource technologies can be most economically exploited if fully utilized by utility companies in support of reliability requirements. We also recommend that NSPI be prepared to provide additional granularity of hosting capacity capability, beyond that contained in the currently posted hosting capacity table, such that renewable energy developers are practically aware of the extent and location of "headroom" available on the distribution system, resulting in the most efficient targeting of distributed resource deployment.

While phasing in such advanced tools may require a staged approach, we recommend that the initial March 2024 update to the hosting capacity table posted in August include a clear direction for achieving coordination between NSPI's reliability needs and the capabilities of solar PV and battery energy storage inverter technologies and controls. We also recommend further technical workshops for stakeholders, held by NSPI, in 2024 to ensure a full understanding of the hosting capacity information published and to allow for ongoing communication to enhance the usefulness of the information to support small scale renewable development, furthering the province's aims.

3.6. Study Grouping and Cost Allocation

This review includes an assessment of how and to what extent interconnection processes and requirements fairly allocate transmission or distribution upgrade costs arising from interconnection, and how group or cluster study processes are addressed in the SGIP and DGIP.

Transmission

For transmission interconnections, NSPI's cost allocation methodology was originally dictated by the Settlement Agreement reached between NSPI and its interveners in the open access transmission proceeding in 2005 (Matter 06341), based on the FERC *pro forma* tariff at that time. The current SGIP group study provisions give NSPI discretion over conducting group, or cluster studies. NSPI states i) that ICs may be grouped depending on whether they requested Energy or Network Interconnection Service and ii) that the remoteness of a facility may prompt NSPI to study the interconnection request separately.[104]

Interconnection customers pay for facilities required to interconnect at the point of interconnection (POI). Based on the results of NSPI's studies, additional upgrade costs may be required on either the transmission or the distribution system. Discussion during the technical conferences focused on distribution system cost allocation concerns by stakeholders. SWEB indicated a number of concerns with technical interconnection requirements for transmission, and also noted the importance of group studies

phase the implementation in order to more quickly publish basic distribution system data or to allow more HCA results to be added over time.

[104] SGIP, 31

and cost sharing mechanisms.[105]

FERC Order 2023 includes updates to the interconnection protocols to account for shared interconnection and network upgrade cost responsibilities, and proportional allocation of such costs among interconnection customers.[106] It recognizes both the complexity of cost allocation within a cluster, and potentially across clusters. To the extent that Nova Scotia transmission interconnection requests may benefit from sharing points of interconnection, or network upgrades arising from cluster study results indicate shared responsibility, the current SGIP cost allocation approach may need to be updated or to clarify such responsibilities. It is possible that with a near-future significant (if not unprecedented) increase in interconnection of renewable sources on the transmission grid, transmission upgrade requirements previously unseen in Nova Scotia's may come to the fore; the updated SGIP should strive to anticipate such outcomes (such as shared interconnection points and shared network upgrade cost responsibility).

Our recommendation section seeks additional input from NSPI after it completes its review of FERC Order 2023, to determine how the SGIP needs to be amended to be in compliance with the essence of the FERC Order, if or as applicable, for cost allocation approaches for transmission interconnection.

Distribution

Stakeholder comments focused on cost allocation methods and IC responsibilities, and NSPI's processes and protocols around distribution system update costs. The NS UARB Decision Letter in the CNMP proceeding accepted NSPI's "cost causation" approach for that docket but expects this Matter to further address mechanisms or methods for distribution upgrade cost allocation for interconnecting small resources. As noted by NSPI, distribution network upgrades are not currently refunded under the DGIP[107] although the small generator interconnection and operating agreement allows for this.[108] NSPI stated that no regulations are in place to establish a refunding mechanism but that one could be instituted.[109]

Essentially, modifications to the existing approach would serve to recognize potential benefits that could accrue to either or both of i) additional ICs using the same distribution system segments with the upgrades, and ii) new and existing load. New load, such as might be seen with additional customer

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[105] SWEB, May 3, page 2. SWEB also suggested "…a group study process and cost-sharing mechanism be developed and implemented by Nova Scotia Power as soon as possible. It is SWEB's experience that not having a clearly defined cost-sharing and group study mechanism prior to receiving the large volume of requests that occur with something like a community-solar RFP will cause severe delays in interconnection studies, and will create several scenarios where viable projects are not realized due to the scenario of a single developer "holding the bag" for the total cost of system upgrades required to connect several generators in queue positions behind them."

[106] FERC Order 2023, paragraphs 422-489.

[107] May 3 Comments, Attachment 1, page 13.

[108] August 10 Comments, page 20.

[109] Ibid.

accounts or with increased load through electrification, could utilize additional headroom created by the upgrade. Existing load could benefit through potential supply-side efficiencies associated with NSPI's generation resources. In an ideal world, all beneficiaries would be identified and all would be allocated a proportionate share of cost responsibility. In the real world, there may be a less perfect approach that doesn't necessary allocate theoretically optimally, but at least attempts to minimize the worst of cost allocation distortions that can result in unfair outcomes and less efficient resource deployment.

NSPI currently uses a traditional "cost causation" approach to allocating distribution system upgrade costs to connecting distributed generators. During the second technical conference participants discussed the different forms of cost allocation that could be used for distribution upgrade cost responsibility.

NREL's 2019 DER Interconnection report[110] provides a construct for considering the forms of cost allocation approaches to consider for distribution upgrade costs associated with distributed resource interconnection:

- Base or traditional cost causer approach:
    - First customer pays for the POI interconnection cost upgrades.
    - First customer pays for "caused" distribution "network"[111] upgrades beyond the POI.

The NSUARB approved this mechanism for use in the CNMP, with expectation that this Matter would address the value of other approaches to cost allocation for distribution upgrades.

The potential shortcomings of using the traditional cost causer approach are as follows, which essentially reflect the potential for multiple beneficiaries:

- Future distributed resource projects can benefit, but don't incur costs, as the cost burden is imposed on the first to trigger the upgrade need.
- Load (existing and future) may benefit but does not contribute to the cost of upgrades.
- A first mover cost imposition could lead to procedural delays, as potential renewable energy developers might attempt to "game" the interconnection queue sequence to avoid cost responsibility.
- Smaller or larger projects may terminate, even though the projects are economical if costs are spread across the full group of benefiting entities.

Alternative approaches to the traditional cost causer convention include the following:

- Refund a portion of the cost imposed on first connectors as incremental DER comes online, based on the results of group studies that indicate multiple benefiting DER providers. The challenges to such a mechanism include project withdrawal, and a need for re-studies. This method has been characterized as "Headaches for utilities and DER

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[110] NREL, *An Overview of Distributed Energy Resource (DER) Interconnection: Current Practices and Emerging Solutions*, April 2019. https://www.nrel.gov/docs/fy19osti/72102.pdf.

[111] In this instance, a distribution "network" upgrade could be required on radial or networked equipment.

applicants" and has been utilized in Massachusetts and California for different tariff regimes.

- Use a cost causer "Post-Upgrade" cost sharing approach. The original developer pays for the upgrade, but eligible costs are reimbursed by future developers. This was used as an interim approach in New York.
- For smaller projects, use a utility pro-rated cost sharing approach, where the utility pays the up-front costs and recovers costs from ratepayers. Hawaii used this approach, as the overall volume of requests was high. In this instance, larger projects used the more traditional cost causer approach.
- The last option in NREL's "box"[112] of alternatives includes what is referred to as "utility pre-emptive upgrade cost sharing". The method has utilities paying for smaller projects, and larger projects paying a pro-rated fee. One example was a New York pilot program where the utility invested in 3VO ground-fault protection, to mitigate the concerns associated with back flow through substation transformers.

M10872 included evidence and closing arguments on the appropriateness of the cost-causer-pays methodology for allocation of system upgrade costs to proponents of net metering projects in the forthcoming Commercial Net Metering Program. As noted, the NSUARB accepted the existing cost causer approach for the CNMP but looks to this Matter to consider the benefits of alternative mechanisms.

NSPI has indicated the "merit in further examining New York's cost sharing mechanism with respect to distribution network upgrades, on the assumption that ICs provide some incremental benefit to the larger system and customers."[113] NSPI also noted the importance of understanding the benefits to ratepayers, if they are to potentially bear some of the costs; and also rightly notes the importance of not creating undue administrative burdens associated with a refund mechanism for IC customers.[114] New York's mechanism would allow for better cost sharing between ICs. However, other states – for

[112] Side Box 5 in NREL's report.

[113] May 3 Comments, Attachment 1, page 13.

[114] August 10 Comments, pages 19-20.

example, Massachusetts[115] and New Mexico[116], in addition to New York[117] – have provisions that could allow some distribution upgrade costs to be at least initially borne by ratepayers through utility capital investment. Generally, these mechanisms require analysis to ensure public benefit from such upgrades. Appendix B contains additional detail on cost allocation approaches for distribution upgrades.

We recommend Nova Scotia update the DGIPs to include a form of pre-emptive upgrade cost sharing as a means of making the overall cost allocation fairer; while striving to keep a simple, workable implementation plan without undue administrative burden. Currently, there are no refunds to original cost-causing DER entities, thus two groups of beneficiaries – load, and other DER providers who interconnect after the first mover, are potentially not contributing towards distribution system investments they benefit from ("free riding"), while the initiating DER provider may be facing unfair economic burdens.

The details of such an implementation matter and are not easily prescribed; thus, we do not attempt to prescribe them here. We recommend NSPI file an alternative cost allocation straw proposal, after completion of the March 2024 hosting capacity update to allow for deliberate, unhurried consideration of these issues while not interfering with the timeline for the hosting capacity update. The straw proposal should set out the following, for further review and stakeholder comment:

- Define two categories of Class 2 projects (small and large) for the purpose of cost allocation for distribution network upgrade costs. All direct interconnection costs remain the responsibility of the IC.

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[115] Massachusetts Department of Public Utilities, Provisional System Planning Program Guide, "The Department of Public Utilities (DPU) is investigating how to improve distributed energy resource planning to further the Commonwealth's progress towards achieving net-zero greenhouse gas emissions. Currently, a distributed generation (DG) facility whose interconnection triggers an upgrade of the electric power system (EPS) must pay for the full cost of that upgrade. These upgrades can be expensive and require extensive system planning and time to construct. In D.P.U. 20-75-B, the DPU established a new, provisional framework for planning and funding essential upgrades to the EPS. The provisional framework allows the electric distribution companies to file capital investment project (CIP) proposals with the DPU. These proposals limit the interconnection costs allocated to each DG facility. Under the provisional design, ratepayers will help fund the initial construction of these EPS upgrades. Ratepayers will be reimbursed over time from fees charged to future DG facilities that are able to interconnect due to the prior upgrades. The DPU will review each CIP on a case-by-case basis for approval, denial, or modification." https://www.mass.gov/guides/provisional-system-planning-program-guide#-4.-cip-filing-requirements-

[116] New Mexico Public Regulation Commission Rule 17.9.568, Cost Sharing for Interconnection Upgrades: Interconnection of Generating Facilities with a Nameplate Rating Up to and Including 10 MW Connecting to a Utility System, at https://www.srca.nm.gov/parts/title17/17.009.0568.html. This section of the rule allows for consideration of cost sharing to other parties including ratepayers, if benefits to others are determined. It states "In making such a determination that there are public benefits to such a cost-sharing mechanism, the commission shall employ the same analysis as provided for cost-sharing or rate basing grid modernization projects as defined by Section 62-8-13 NMSA 1978 (Grid Modernization Act 2019, HB 233) to make a finding that the approved expenditures are: **(a)** reasonably expected to improve the public utility's electrical system efficiency, reliability, resilience and security; maintain reasonable operations, maintenance and ratepayer costs; and meet energy demands through a flexible, diversified and distributed energy portfolio; **(b)** reasonably expected to increase access to, and use of, clean and renewable energy, with consideration given to increasing access to low-income subscribers and subscribers in underserved communities; **(c)** designed to contribute to the reduction of air pollution, including greenhouse gases;"

[117] New York State Standardized Interconnection Requirements, at May 2022 SIR - Final - DMM.pdf (ny.gov). New York's requirements use a 50 kW and a 5 MW threshold classification in their rule. The rule includes a utility Capital Investment Program sub-section that allows utilities to proactively invest to increase hosting capacity.

- Establish a proportionate (per kW) contribution amount from smaller Class 2 projects, to contribute towards an aggregate "pool" of funds for such upgrades, complemented by NSPI capital investment (distribution system) for those required distribution network upgrades.
- Base the proportionate (per kW) contribution amount assuming 50% of the total network upgrade costs are borne by ICs, and 50% is carried by NSPI as a rate based distribution investment.

  NSPI currently includes many distribution and transmission assets in base rates, for infrastructure that is both localized and supportive of overall reliability for customers. Using this same vehicle for a portion of the cost of network upgrades on the distribution system is reasonable. We recommend the use of a 50/50 split in recognition of the difficulty in projecting future streams of benefits to ratepayers from increases in small scale (non-NSPI) renewable resources across Nova Scotia. The allocative share, along with the mechanism itself, should be reviewed within a few years (and somewhat regularly thereafter) to gauge its effect on promoting small scale renewable energy development that benefits not just the IC but ratepayers on the whole. Such reviews should include at least high level analyses to gauge overall ratepayer benefit from such distribution network upgrades.
- For larger Class 2 projects, create a simple refund structure to allow for refunding a portion of the initial network upgrade cost to the IC as incremental IC customers are interconnected. For this larger class of projects, also allow for a smaller portion (less than 50%) of the total network upgrade costs to be funded from NSPI rate based distribution investment, for the same reasons as noted above for smaller Class 2 projects. Initially, we recommend 25% of the overall network upgrade cost for these larger projects be sourced from the NSPI rate based investment.

As noted in Appendix B, different state jurisdictions are formulating different approaches to the same problem of considering the fairer and more efficient means for funding distribution network upgrade costs that arise in large part from DER requests, but that benefit more than just the originating DER party. The above recommendation is intended to set a modifiable course for Nova Scotia.

4. Recommendations on Substantive Issues

4.1. Overview

This section summarizes Synapse's recommendations for changes to NSPI's interconnection protocols to reflect mechanisms to "ensure the best value for ratepayers and consistency and predictability for generators,"[118] given the current resources available in the marketplace and Nova Scotia's requirements for the essential transformation of its electricity supply to include a high percentage of renewable

[118] NSUARB, Terms of Reference M10905.

energy. The protocols include the procedures documents (SGIP and DGIP), the associated technical interconnection documents, the generation (large and small) interconnection agreements, and the study agreement documents.[119] The recommendations are based on our interconnection policy review findings in this Matter, including NSPI responses and comments, other stakeholder comments, discussion at the two technical conferences, best practices considerations including IREC issuances, and Nova Scotia's needs to meet policy requirements to increase renewable generation.

The changes required for both transmission (SGIP) and distribution (DGIP) protocols involve near-term (2023) updates to reflect well understood and relatively uncontentious, necessary modifications (for example, anticipated changes reflected in NSPI's August 10 Comments) or modifications consistent with the Board's Decision Letter in the CNMP proceeding, for similarly situated or attributed resources. They also include, in 2024 and beyond, i) further updates reflecting ongoing NSPI consideration of the effect of FERC Order 2023 on the SGIPs, ii) further distribution system protocols modifications after or simultaneous with development of more advanced hosting capacity information (e.g., the nature and impact on resource development of a dynamic hosting capacity analysis), and iii) updates to both SGIP and DGIP, and related protocols documents, based on lessons learned as NSPI expands its capacity to perform interconnection studies in support of the large volume of renewable resource interconnections that will be needed in Nova Scotia between now and 2030 - and in later years.

The recommendations directly consider NSPI's August 10 Comments in this Matter, which include substantive plans for SGIP and DGIP modification. They are intended to support continuing improvement in the GIPs as NSPI works to i) establish and evolve distribution hosting capacity systems, ii) complete a series of system interconnection studies (feasibility, system impact and facility) for a sizable number of projects that initiated interconnection requests during 2023 and 2022, and iii) refine the SGIP to reflect the impact of FERC's Order 2023 on transmission providers (such as NSPI) that have an open access transmission tariff.

Synapse recommends modification to the SGIP and DGIP documents, the technical Interconnection Requirements documents for transmission, distribution (less than 100 kW) and distribution (more than 100 kW), and all related interconnection and interconnection study agreements in line with the specific recommendations that follow. Redline versions reflecting the specific changes to the documents should accompany all filings.

4.2. Transmission System Interconnection

1. **Modify SGIP to address study fee structures and service standard timelines for "small" resource category**. NSPI has suggested a new threshold representing a "small" resource connected to the transmission system, such as may be seen with Community Solar PV projects

[119] NSPI has indicated in its May 3 Comments that it intends to modify various aspects of its SGIP and DGIP and associated and supporting documents.

too large for distribution system interconnection or those having an impact on the transmission system. We recommend the following:

- Modify the SGIP to codify the suggested 10 MW size as "smaller" transmission system interconnection threshold value. Report annually on the effect of this change on interconnections, with particular examination of its effect on Community Solar development.
- Modify the SGIP to reduce study deposits and reduce re-study deposits for these categories of interconnection requests.
- Modify the SGIP to codify reduced study timelines associated with fast tracking of this class of resource.

2. **Incorporate battery energy storage system resources into SGIP**. Incorporate new specific provisions for battery energy storage system resources (stand-alone and/or paired with solar or wind) for transmission system interconnection protocols. We recommend the following:

    - Modify the SGIP to include separate battery resource type of interconnection, to distinguish from generation resource interconnection.
    - Modify the SGIP to include use of IC operational intention to shape the study metrics used by NSPI to model the impact of the battery resource on the grid. This is also one of the outcomes of the FERC 2023 reforms and will help to prevent unnecessary or excessive interconnection or network upgrade costs associated with battery resource connection.
    - Modify the technical Transmission System Interconnection Requirements document to directly include battery energy storage distinctions and requirements.

3. **Add interconnection study capability resources to improve study timelines and develop a pre-application report process to replace feasibility study step**. Nova Scotia's policy goals to dramatically increase the level of renewable energy requires a significant step up in interconnection study activity. FERC Order 2023 has at its core a goal of improving generation interconnection procedures, fully complementary to Nova Scotia's aims. The elimination of the "reasonable efforts" standard in the FERC Order will generally require transmission providers to either i) be more efficient with interconnection study processes, or ii) increase technical and resource capabilities to complete studies in a more timely manner than has been seen. Both of these steps will likely be needed to meet the aim of the FERC Order, and to meet Nova Scotia's policies. We recommend the following:

    - Explicitly and proactively plan for the development of internal or external resources (or a combination) to effectively increase both near-term and longer-term interconnection study resource capability, to improve the overall efficiency (i.e., reduce the overall time to completion) of interconnection processes and enable alignment of NSPI's SGIPs to meet Nova Scotia's renewable energy increase requirements and effectively comply with the elimination of the "Reasonable Efforts" standard as seen in FERC Order 2023. Align such efforts with study needs associated with distribution requirements.

- Provide a detailed plan to NSUARB to accomplish the increase in interconnection study capability, accounting for the need for steadily increasing renewable resource procurement as contained in the NSPI IRP and the 2023 10 Year System Outlook. The plan should have clear indications of the costs and the mechanisms anticipated to ensure such capability increases.

- Develop a pre-application reporting mechanism to replace the feasibility study, akin to the pre-application report in the CNMP and as recommended for the DGIPs in general. This would also serve as the mechanism aligning with the "heat map" requirement in FERC Order 2023. This would replace the current feasibility study step in the SGIP. Alternatively, after detailed review of the FERC Order 2023, suggest modifications to the SGIP to effectively meet this requirement.

- Follow the FERC Order 2023 reform pathway for cluster studies, consistently aligning interconnection evaluation and study processes to accommodate a pre-application step for individual projects, a cluster study process for system impact studies, followed by facility study planning as necessary.

4. **Conduct further review of Order 2023, continue with modifications to the SGIP as necessary in 2024 and beyond, and provide annual reporting on the effects of increasing study capability.** While we recommend near-term changes to the SGIP to incorporate the smaller project threshold (10 MW), battery energy storage requirements, and a form of pre-application report as noted in the recommendations above, the full sweep of Nova Scotia's needs to reach renewable requirements and the breadth of changes in FERC Order 2023 will likely result in a need for ongoing refinements to the SGIP. We recommend the following:

   - Continue review of the FERC Order 2023 and incorporate additional SGIP changes as necessary or required in 2024 and beyond. We recommend NSPI include an update in the first half of 2024 indicating its findings from review of the FERC Order and explaining the thrust of, and rationale for, any additional changes to the SGIP.

   - Conduct an initial review one year after implementation of near-term SGIP modifications (recommendations 1 and 2 above), also including a status update of the initial effects of increasing interconnection study capability. Within two years after the implementation of initial SGIP changes, provide a fulsome analysis of the impact of the changes with specific findings on study timing results and lessons learned.

4.3. Distribution System Interconnection

1. **File DGIP modifications with the Board**. NSPI clarifies that DGIP amendments are not typically submitted to the NSUARB.[120] For this review, we recommend filing with the Board due to the overlap with CNMP modifications, commonalities with changes made to the SGIP (e.g., battery energy storage provisions and resources for impact studies) and continued interest in and expectations for small renewable development province wide.

2. **Modifications to the DGIP – structure, fees, timelines**. We recommend the following:

    - Modify the DGIP to include a pre-application report process for all Class 2 interconnection requests.
    - Modify the DGIP to lower the DSIS deposit to $2,500 for certain Class 2 IBR resources that meet the size and voltage thresholds noted by NSPI (less than or equal to 500 kW for resources connected at 12.5 kV, and less than or equal to 1 MW for resources connected at 25 kV).
    - Modify the DGIP to update the study timelines for fast tracking of resources that meet the IBR threshold sizes.

3. **Pre-application reporting for non-CNMP customers**. We recommend the following:

    - Institute a form of pre-application reporting for non-CNMP customers.
    - Confirm that pre-application reporting may, or could, indicate no need for DSIS study and potential for elimination of DSIS study deposit for certain Class 2 IBR resources that move from the pre-application stage to the interconnection request stage. If so, ensure that the interconnection process and documents allow for this.

4. **Modifications to the DGIP – battery energy storage resources.** We recommend the following:

    - Modify the DGIP to explicitly define and include battery energy storage resources as separate from generation resources.
    - Incorporate new specific provisions for battery energy storage system resources (stand-alone and paired with solar) for distribution system interconnection protocols and ensure that technical interconnection documents for both Class 1 and Class 2 level facilities include the necessary modifications to incorporate these resources.

5. **Modifications to the DGIP – hosting capacity.** We recommend the following:

[120] August 10 Comments, Appendix A, page 1.

- Modify the DGIP to describe how hosting capacity information just released and planned dynamic hosting capacity information will affect need for DSISs and how it will interact with pre-application reporting.
- Develop specific timetable, milestones and information granularity for planned March 2024 hosting capacity analysis update.
- Create a hosting capacity map structure in addition to provision of tabular data, for visual support for small scale renewable energy and battery storage development.

6. **Update the hosting capacity table by March of 2024.** We recommend:
    - Work towards refining and supplementing the existing information to create a path towards a "coordinated dynamic" hosting capacity analysis. Developing such a platform for information dissemination will eventually allow for a potential "flexible" form of interconnection service, with efficient utilization of existing distribution assets, and more optimal locational deployment of distributed resources.
    - Conduct hosting capacity technical workshops in later 2024, after release of the updated dynamic hosting capacity map / analysis.
7. **Develop Cost Allocation Straw Proposal for Distribution Network Upgrades**. Develop a straw proposal for an alternative shared cost allocation for distribution network upgrades, as described in this report.
8. **Improve DSIS study capability resources**. In alignment and consistent with the recommendations in the transmission section, deploy new staff resources to proactively improve study timing for all required DSISs and report annually on effectiveness of improvements.
9. **Modify the Distribution Interconnection Requirements technical document**. The document should explicitly include battery energy storage and should include at least a subsection defining how electric vehicle supply equipment, both existing (generally load only) and future (bi-directional) fits in to resource classifications in the document.
10. **Support Development of Additional Distribution Network Upgrade Cost Refund Regulation**. Develop a cost sharing regulation for distribution network upgrade costs for any portion of new cost allocation protocols that include refunding cost to "first moving" DER parties responsible for certain portions of distribution network upgrade costs.

Appendix A: NSPI Transmission & Distribution Interconnection Queues (September 2023)

APPENDIX B: OTHER JURISDICTIONS – CANADA AND US

Other Jurisdictions – Canada

Other jurisdictions in Canada provide points of comparison for interconnection procedures, costs, and timelines. Here, we highlight interconnection processes in the Canadian provinces of New Brunswick, Newfoundland, and British Columbia. Each province follows the same general set of procedures for large projects that consists of preliminary assessment, system impact study, and facilities study. In New Brunswick and British Columbia, there are more streamlined processes available for small projects (<1 MW) that may eliminate the need for system impact and facilities studies. These jurisdictions also provide hosting capacity information prior to application for these smaller projects. British Columbia extends access to hosting capacity information to smaller projects (up to 35 kV) seeking to connect to the distribution system.

New Brunswick, Newfoundland and Labrador, and British Columbia Interconnection Information

Size and Type	Process	Application Fee/ Parameters	Study Fee / Parameters	Timeline	Prioritization	Other
New Brunswick						
Embedded generation	1.) Site identification using distributed generation capacity map 2.) Submit general capacity assessment form for NB power to assess capacity requirements 3.) Submit an Embedded Generation Interconnection Application form	$10,000 with Embedded Generation Interconnection Application	$500 for capacity assessment	No information provided	No information provided	Provides a hosting capacity map for the site identifying stage Program not currently accepting new applicants
For added generation, including embedded generation over 1 MW	1.) Request for Connection Assessment 2.) Feasibility review 3.) System Impact Study 4.) Facilities Study	Non-embedded generation projects: $5,000 per project plus taxes with the application For other projects, including, embedded generation projects, and assessments of Point to Point	Transmission Provider will record actual costs of System Impact Studies and Facilities Studies and will invoice these costs to Connection Applicants, net of deposit amounts.	1.) Feasibility Review: within two weeks of completed application typically 2.) System Impact Study: typically takes 1 month	Capabilities of existing system are allocated on a "first-come, first-served" basis. First priority for transmission reservation status is given to projects associated with firm	

Synapse Energy Economics, Inc.

Size and Type	Process	Application Fee/ Parameters	Study Fee / Parameters	Timeline	Prioritization	Other
		transmission service greater than 100 MW: $5,000 per project plus taxes with the application All other projects: $0		3.) Facilities Study: typically takes 1 month	transmission service: • Firm for at least five years • Transmission service must be for at least 50% of project size • Project may acquire transmission service directly or indirectly by contracting with another transmission user who can provide the transmission service	
Newfoundland						
	1.) Application for Eligible Customer Status 2.) Application for Generator Interconnection: applicant shall submit a separate Interconnection Application for each proposed Point of Interconnection 3.) System Impact Study 4.) Facilities Study	Application for Generator Interconnection: $10,000 deposit; additional $20,000 deposit for applicants that have not provided documentation of ownership, a right to develop, or an option to purchase or acquire an interest in land area equal to at least 50% of that required for the purpose of constructing the proposed Generating facility	Applicant will compensate NLSO for actual cost of the SIS and Facilities Study. Applicant must pay security deposit.	Not provided	NLSO shall assign a Queue Position to each Completed Interconnection Application based upon the date- and time-stamp of its submission	
British Columbia						
Over 35 kV	1.) Interconnection Request 2.) Feasibility Study (optional) 3.) System Impact Study 4.) Facilities Study	$15,000 deposit	Feasibility Study: $15,000 deposit (billing based on actual costs) System Impact Study: $75,000 deposit (billing based on actual costs)	Feasibility Study: completed within 60 calendar days System Impact Study: completed	Requests for interconnection handled on a first-come, first-served basis	

Size and Type	Process	Application Fee/ Parameters	Study Fee / Parameters	Timeline	Prioritization	Other
	5.) Interconnection Agreement		Facilities Study: $150,000 deposit (billing based on actual costs)	within 150 calendar days		
Under 35 kV	1.) Basic distribution system information request 2.) Screening study (optional) 3.) System Impact Study 4.) Facilities Study 5.) Interconnection Agreement	Basic Distribution System Information Request: $210, but the first two requests in any 12-month period are free	Screening Study: $5,000 flat cost System Impact Study: deposit required up front (based on estimated cost to complete the work); any overages are billed on actual cost once SIS is finished; any balance will be refunded; typical SIS can cost between $20,000 and $130,000 Facilities Study: Cost of Facilities Study estimated in SIS report; BC Hydro to bill actual study cost once study completed; typical costs range from $50,000 to $350,000	Information request: typically less than two weeks Screening study: typically 4–8 weeks SIS: typically 4–12 months Facilities study: typically 6–12 months	Requests for interconnection handled on a first-come, first-served basis	Basic distribution system information request provides info on if the proposed project capacity can be injected into the system at the identified point-of-interconnection
Micro-generator projects (over 100 kW and up to 1 MW)	1.) Basic distribution system information request 2.) Screening study May need a system impact study or may qualify for streamlined design stage application process					

[1] NB Power, Embedded Generation Application Process (2021). Available at: https://www.nbpower.com/en/products-services/embedded-generation/application-process/; [2]NB Power, Electricity Business Rules: Appendix B - Connection Assessment Procedure (2012). Available at: https://tso.nbpower.com/Public/en/docs-EN/ebr/Appendix%20B%20(Connection%20Assessment%20Procedure).pdf; [3] Newfoundland and Labrador System Operator (NLSO), Generator Interconnection Procedures (GIP) (2018). Available at: http://www.oatioasis.com/NLSO/NLSOdocs/Generator_Interconnection_Procedures_FINAL_02152018.pdf; [4]BC Hydro, Distribution Generator Interconnections (2023). Available at: https://app.bchydro.com/accounts-billing/electrical-connections/distribution-generator-interconnections.html; [5]BC Hydro, Transmission Generator Interconnections (2023). Available at: https://app.bchydro.com/accounts-billing/electrical-connections/transmission-generator-interconnections.html.

Other jurisdictions do not have the same requirements as Nova Scotia to move through the interconnection process. For example, Newfoundland has the following minimum requirements for entering the queue for SIS:

1. The applicant has been deemed an eligible customer (meets creditworthiness requirements, is in good standing with the NLSO, not in default with NLSO or an individual transmission owner, and provides NLSO with all required legal identifiers);

2. A completed Interconnection Application with all relevant data and information;

3. A $10,000 deposit; and

4. Documentation of ownership, a right to develop, or an option to purchase or acquire an interest in a land area equal to at least 50 percent of that required for the purpose of constructing the proposed Generating Facility, or an additional deposit of $20,000.[121]

BC Hydro requires interconnection customers to submit reasonable evidence of one or more of the following at the time of executing a final Standard Generator Interconnection Agreement (SGIA):

1. The execution of a contract for the supply or transportation of fuel to the generating facility;
2. The execution of a contract for the supply of cooling water to the generating facility;
3. The execution of a contract for the engineering for, procurement of major equipment for, or construction of, the generating facility;
4. Execution of a contract for the sale of electric energy or capacity from the Generating Facility; or

Application for an air, water, or land-use permit.[122]

US Group Study and Cost Sharing

Two of the biggest challenges jurisdictions face when optimizing interconnection processes are how to expedite interconnection timelines through group study processes and how to allocate the costs associated with systems upgrades to accommodate interconnection requests. In general, utilities can recover costs by directly assigning them to generators and/or distribution loads, or through different types of transmission service.[123] To help Nova Scotia identify the emerging trends and best practices in cost-sharing and group studies, this section reviews some of the group study and cost-sharing activities within U.S. states,[124] at the Federal Energy Regulatory Commission (FERC), and across the U.S. Regional Transmission Operators (RTO)., and within U.S. states.

Individual state cost-sharing programs, some of which have gone through several iterations, offer lessons on how best to implement a cost-sharing policy in Nova Scotia. Here, we have identified some best practices from Minnesota, Massachusetts, New Mexico, New York, and California. See the summary table below for a comparison of cost-sharing policies across select states.

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[121] Newfoundland and Labrador System Operator (NLSO), Generator Interconnection Procedures (GIP) (2018). Available at: http://www.oatioasis.com/NLSO/NLSOdocs/Generator_Interconnection_Procedures_FINAL_02152018.pdf;

[122] BC Hydro, Open Access Transmission Tariff Attachment M-1: Standard Generator Interconnection Procedures (2023). Available at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/tariff-filings/open-access-transmission-tariff/16-attachment-m1-oatt.pdf.

[123] WKM Energy Consultants Inc. 2016. *Survey of Transmission Tariff Rates and Cost Allocation by Function in Canadian Provinces*.

[124] Lawrence Berkeley National Laboratory, *Generation Interconnection Costs to the Transmission System* (2023). https://emp.lbl.gov/interconnection_costs, summarizing interconnection trends and costs across MISO, SPP, NYISO and ISO New England.

Sharing Costs with Future Projects

IREC supports the Minnesota Commission's approval of the April 2022 cost-sharing policy, which places no cost burden on ratepayers despite Xcel Energy 's proposal to do so. Rather, it requires all interconnecting projects under 40 kW to pay a flat fee of several hundred dollars that will contribute to a pool of funds used to pay for necessary grid upgrades.[125] The Commission also instructed Xcel to start reviewing multiple interconnection proposals at once in a cluster approach.[126]

In contrast, Massachusetts' provisional cost-sharing framework allows the electric distribution companies to file capital investment project proposals with the Department of Public Utilities (DPU), which allows ratepayers to help fund the initial construction of grid upgrades. Ratepayers, however, will be reimbursed over time from fees charged to future distributed generation facilities that are able to interconnect due to the prior system upgrades.[127] There is also a $500-per-kilowatt limit on the cost of a project approved by the DPU (based on a group or cluster study and identifying the level of DER capability with the new upgrades), and the DPU will review each capital investment project on a case-by-case basis for approval, denial, or modification.[128]

The New Mexico Public Regulation Commission adopted a November 2022 order requiring that distribution utilities use a multiple-screening process for smaller (≤25 kW) projects with the aim of reducing the volume of redundant interconnection requests and also reducing the processing required for smaller (≤25 kW) projects that a distribution utility would need to evaluate.[129]

New York takes another approach: the current cost-sharing mechanism allows some unrecovered interconnection costs to be borne by ratepayers, but only up to an annual cap at 2 percent of the utility's distribution/sub-transmission electric capital investment budget per fiscal year.[130]

Cost-sharing between future distributed generation projects through fees or *pro rata* capital cost-sharing is commonplace and helps allocate the cost burden among those that most directly benefit now and in future years. California implemented this concept in its cluster-study process; New York's cost-sharing process shares costs between developers who benefit from distribution system upgrades; and

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[125] Jossi, Frank. 2022. "Minnesota regulators want XCEL to cut wait time for connecting solar to its grid." *Energy News Network*. Feb. 15. Available at: https://energynews.us/2022/02/15/minnesota-regulators-want-xcel-to-cut-wait-time-for-connecting-solar-to-its-grid/.

[126] IREC News, 2022. "MN Interconnection Ruling Contains Some Wins and a Major Threat." Available at: https://irecusa.org/blog/irec-news/mn-interconnection-ruling-contains-some-wins-and-a-major-threat/.

[127] Massachusetts Electric Power Division, 2022. "Provisional System Planning Program Guide." Available at: https://www.mass.gov/guides/provisional-system-planning-program-guide.

[128] Ibid.

[129] Interstate Renewable Energy Council. "How New Mexico's New Interconnection Rules Position It as a Clean Energy Leader." December 7, 2022. https://irecusa.org/blog/regulatory-engagement/how-new-mexicos-new-interconnection-rules-position-it-as-a-clean-energy-leader/.

[130] Judge, Michael et al., 2022. *Integrating Distributed Solar and Storage: The Keystones of a Modern Grid*. Coalition for Community Solar Access. Available at: https://www.communitysolaraccess.org/wp-content/uploads/2022/02/CCSA_BRO-White-Paper_20220214.pdf.

Massachusetts collects fees from future distribution system upgrade users to pay down the initial upgrade investment. These examples all feature cost-sharing; the differentiating factor is who future project developers pay—either the triggering project owner (e.g., New York) or ratepayers, via the utility (e.g., Massachusetts).

Group Interconnection Study

Grouping interconnection projects helps streamline review, identify necessary system upgrades, and allocate costs among projects that share in the benefits created by an upgrade. California and Minnesota have implemented group or cluster interconnection studies. Massachusetts requires it for capital investment projects under the Provisional System Planning approach.

Proactive Spending

If a utility identifies a distribution system upgrade, it can proactively help create more hosting capacity by putting out a call for projects that can help shoulder the cost. This is a feature of New York's newest cost-sharing policy. Under the policy, a utility can initiate system upgrades by identifying the cost of upgrading substations to create additional hosting capacity. It will also issue a deadline for additional distributed generation projects to submit interconnection applications at those substations. After the established deadline, the utility will determine a cost per kilowatt for the upgrade at each relevant substation. The utility will also have the discretion to move ahead with the upgrade once the DER ICs have committed to paying their assigned shares. This model allows projects to pool resources before they are approved to help ensure that, if they are approved, the grid can handle their interconnection. Projects that withdraw from the queue after paying their share are not refunded.[131]

Cost Envelope

Limiting upgrade costs to within a range of an initial estimate helps provide financial certainty to DER developers. Both California and Massachusetts have implemented a plus-or-minus 25 percent cost envelope.[132] If the actual cost exceeds the estimate, the difference is typically the responsibility of the transmission owner and its shareholders.

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[131] State of New York Public Service Commission, 2022. "Order Approving Cost-Sharing Mechanism and Making Other Findings." Cases 20-E-0543 and 19-E-0566. Available at: https://www.nyseia.org/_files/ugd/a89dc9_7e6753f13be34be98574867398045ad5.pdf.

[132] McConnell, E., C. Malina, 2017. "At What Price? How to Improve Interconnection Cost Certainty and Predictability." *Greentech Media*. June 12. Available at: https://www.greentechmedia.com/articles/read/at-what-price-how-to-improve-interconnection-cost-certainty-and-predictabil.

Allocating Shared Upgrade Cost when a Project Leaves the Queue

If a project leaves the interconnection queue after committing to pay for a grid upgrade, there must be a mechanism for handling the portion of the cost it was expected to pay. Current examples present four options: (1) allocate that portion to remaining projects in the group (California), (2) refuse to refund projects that pay and then drop out (New York), (3) disperse costs to ratepayers (New York in some circumstances), or (4) only allow projects that have approval to participate in cost-sharing (this is not a known policy in any state studied).

Summary: Distributed Resource Interconnection Process, Structure, Fees, Timelines, Costs and Cost Allocation at Selected US State Jurisdictions

	New York	New Mexico	Massachusetts	Minnesota	Hawaii
Interconnection process and timeline	Applicant submits application through Interconnection online Application Portal. Utility performs preliminary screening analysis within 15 days. If applicant passes, can proceed to interconnection. If not, applicant can take multiple pathways, included a Coordinated Electric System Interconnection Review (CESIR), for which utility will provide a cost estimate to the applicant. CESIR to be completed within 60 days. If applicant instead choses to proceed with a supplemental screening analysis, customer must pay a non-refundable fee of $2,500 and actual costs of up to $5,000.[133]	Four levels of technical screens: 1. Simplified process (least impactful interconnections); 2. Fast Track; 3. Suplemental reviews 4. Detailed Study process. 2022 order changed rule triggering technical reviews/ not allowing applicants through simplified process. Changed from: to go through simplified process, applicants had to be seeking interconnection on distribution circuits with < 15% "penetration" (aka aggregate capacity of DER). Now, aggregate export capacity cannot exceed 100% of relevant minimum load normally supplied by circuit.[134]	Customer can go through three pathways of interconnection: 1) simplified – for facilities <15kW single phase or <25kw, and some other specific facilities; 2) expedited – facilities must pass pre-specified screens and 3) Standard. Maximum days for standard process = 135= Review Application for Completeness (10 days, includes 3 days to Acknowledge Receipt of Application) + Complete Standard Process Initial Review (20 days) + Send Impact Study Agreement (5 days) + Complete Impact Study (if needed, 55 days) + Complete Detailed Study (if needed, 30 days) + Send Executable Agreement (15 days) = 135 total aggregate days.	Parallel review of small projects or fast track projects with no known capacity constraints allowed. Simplified Process: for certified inverter based DERs with capacity of 20 kW ac or less. If project doesn't pass initial review screens, will be routed to fast track. Fast track eligibility based on line voltage and size[135]	Following application submittal, company completes Initial Technical Review. Systems that qualify as customer self supply and NEM+ will qualify for expedited interconnection. If system doesn't pass initial technical review, must complete a supplemental review, which will either result in: 1) qualifying for Simplified Interconnection, 2) additional interconnection requirements and associated costs or 3) requiring an interconnection requirements study (IRS).[136]

133 NY SIP https://www.nyseia.org/_files/ugd/a89dc9_7e6753f13be34be98574867398045ad5.pdf

134 Page 26 of Pdf: commission NM 2022 final order https://irecusa.org/wp-content/uploads/2022/12/NM-Interconnection-21-00266-UT-2022-11-30-Final-Order.pdf

135 P. 10-14 of MN DIP pdf MN DIP_tcm14-431769.pdf

136 HECO Rule 14H Appendix III Interconnection Process Overview pg 127 of pdf. https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaiian_electric_rules/14.pdf

Interconnection study timeline	Coordinated Electric System Interconnection Review (CESIR) to be completed within 60 business days of receipt of interconnection design package, proof of site control, contact information, electrical studies, and receipt of payment fee.[137]	30 business days completion when no upgrades required, 45 when upgrades required.[138]	Interconnection impact study for standard process must be competed within 55 days following signing of impact study agreement. If customers agree to a Group Study, Company must complete study within 100-160 days, depending on number of applications and size. [139] Additional timelines for each step/ process described in Tables 1-4.[140]	System Impact Study shall be completed within 30 business days after system impact study agreement is signed. [141]	Supplemental Review complete within 20 business days. If Interconnection Requirement Study (IRS) is required, must be completed within 150 calendar days. [142]
Interconnection study and application costs	Customer pays application fee	Applicant pays all study costs, based on utility's actual costs. Application fees: $150 is nameplate kW <= 25; $300 +$1/ kW for 25-100kW; $300 +$1/kW if >100kW and for facilities that are non-export only, $150 if <100kw and $300 if >100 kW. [143]	Electric distribution company can suggest projects can do a group study [144] Expedited and Standard projects requesting or required to get a pre-application report must pay fee ($100-$750 depending on size)[145] Fees described in Table 6 of Standards for Interconnection of DG.	Customer can request pre-application report for $300. Processing fee for Simplified process= max $100. Certified fast track eligible applications fee: $100 +$1/kW. Non-certified fast track eligible applications fee: $100 +$2/kW. Application not eligible for fast track or simplified process: $ down payment	Customer pays for IRS. The Company may consolidate studies for facilities on the same distribution feeder, in which case applicants can share study costs. [146]

137 NY SIR p. 10 of pdf

138 Lines 169-172 p. 34 of NM interconnection 2022 final order: https://irecusa.org/wp-content/uploads/2022/12/NM-Interconnection-21-00266-UT-2022-11-30-Final-Order.pdf

139 Standards for Interconnection of Distributed Generation p34 of pdf

140 Standards for Interconnection of Distributed Generation

141 MN DIP 4,3.5 - p21 of pdf.

142 HECO Rule 14H Appendix III Interconnection Process Overview page129 of pdf https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaiian_electric_rules/14.pdf

143 NMPRC Rule 17.9.568 https://www.srca.nm.gov/parts/title17/17.009.0568.html

144 Distribution Group Studies | Eversource

145 Standards for Interconnection of Distributed Generation pg 23

146 HECO Rule 14H Appendix III Interconnection Process Overview page 150 of pdf https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaiian_electric_rules/14.pdf

				not to exceed $1,100 + $2/kW towards deposit required for study	
Cost causality	Under cost sharing 2.0, the project triggering the upgrade initially bears 100% of project cost. Subsequent projects benefiting from upgrades will reimburse the triggering project developer until the capacity of the upgrade is used up or net costs to participating projects falls to $100,000. [147]	Currently project causing upgrade pays cost but commission is exploring other methods of cost sharing; Commission may" consider, on a case by case basis, whether a particular situation may be eligible for cost-sharing (whether among similarly situated applicants or in rates)."[148]	Currently, project is responsible for all upgrade costs. DPU established a provisional framework allows the electric distribution companies to file capital investment project (CIP) proposals with the DPU. The proposals limit the interconnection costs allocated to each DG facility, a maximum of $500/kW. Instead, ratepayers help fund the upgrades and are reimbursed over time from fees charged to future DG facilities that are able to interconnect due to the prior upgrades.[149]	Applicant pays for all necessary upgrades. In a March 2022 order, Commission approved a pilot mandatory group studies for three or more applications > 40kw that cannot be reviewed in parallel. The Commission also approved cost sharing for projects <40kW, capped at $15,000 per customer upgrade. Applicants pay a fixed fee that contributes to a pool of funds.[150]	Project triggering upgrades is responsible for costs. If company identifies that the upgrades produce utility system benefits, the applicant will be paid a credit reflecting those benefits (e.g., a planned distribution system addition may be deferred or displaced due to the upgrade associated with the interconnection)[151]
Hosting capacity information requirements	Utilities must provide a hosting capacity map and must update the hosting capacity values at least annually, based on interconnection volumes, capabilities, and resources of each utility.[152]			Xcel Energy required to provide a color-coded, map-based representation of the available Hosting Capacity down to the feeder level, updated annually.[153]	

[147] NY SIR https://www.nyseia.org/_files/ugd/a89dc9_7e6753f13be34be98574867398045ad5.pdf

[148] Paragraphs 173-176 p. 335 of NM interconnection 2022 final order: https://irecusa.org/wp-content/uploads/2022/12/NM-Interconnection-21-00266-UT-2022-11-30-Final-Order.pdf

[149] Provisional System Planning Program Guide | Mass.gov

[150] March 2022 order:

[151] HECO Rule 14H Appendix III page 151 of pdf. https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaiian_electric_rules/14.pdf

[152] NY PSC March 9, 2017 Order on Distributed System Implementation Plan Filings https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bF67F8860-0BD8-4D0F-80E7-A8F10563BBA2%7d

[153] Commission requires utilities to file Hosting Capacity Report every Nov 1

Hosting capacity information available	ConEd has a hosting capacity map.[154] Additional information available on Joint Utilities Data portal [155]	Xcel energy provides hosting capacity map and hosting capacity analysis refreshed annually. [156]	Utilities have hosting capacity maps[157]. Eversource also has an Interconnection Analysis Portal that allows developers to view hosting capacity, estimate cost of solar interconnection, and search for land parcels based on hosting capacity, project size, etc.[158]	Xcel Energy hosting capacity map[159]	Yes, but seems less detailed only show primary distribution network[160]

154 Con Edison Hosting Capacity Maps | Con Edison

155 Utility System Data Portal | Joint Utilities (jointutilitiesofny.org)

156 https://mn.my.xcelenergy.com/s/renewable/developers/interconnection/hosting-capacity-map

157 Hosting Capacity Map Massachusetts | Eversource

158 User guide: PowerPoint Presentation (eversource.com) Portal Website: Interconnection Analysis Portal | Eversource

159 Xcel Energy - Hosting Capacity Map

160 https://www.hawaiianelectric.com/clean-energy-hawaii/integration-tools-and-resources/locational-value-maps

Federal Energy Regulatory Commission

FERC Interconnection Rulemaking

In June of 2022, FERC began a rulemaking to reform regulations and processes governing how RTOs handle interconnection.[161] Among the reforms in its Notice of Proposed Rulemaking (NOPR), FERC proposed implementing: (1) a first-ready, first-served approach; (2) re-study procedures; (3) hosting capacity maps and reporting; (4) delay resolution processes; (5) readiness requirements; (6) and memorializing operational parameters and co-location. On July 28, 2023, FERC issued its Order 2023 codifying the reforms from the NOPR.

Under the proposed first-ready, first-served cluster study process, transmission providers would conduct larger interconnection studies encompassing numerous proposed generating facilities, rather than separate studies for each individual generating facility. Another issue this NOPR seeks to solve is the speculative queuing of ICs and their withdrawal from the queue upon learning the final project and upgrade costs necessary to interconnect. Because this restarts the study process, it can cause protracted study timeframes and thus delays. The NOPR's solution is a cluster study approach with a single annual period of re-studies. FERC also explicitly acknowledged the benefit of hosting capacity reporting and proposes an interactive map that ICs can reference to identify geographically where hosting capacity is available. The NOPR proposes to impose firm deadlines on transmission providers and levy penalties if they fail to complete interconnection studies on time.

Among the more controversial measures in the NOPR is requiring ICs to demonstrate financial and developmental readiness. To do so, the IC must show their facility has either been selected in a resource plan or identified in a resource solicitation. ICs argue they need a valid interconnection request and queue position to be considered in some solicitations or resource plans, and thus a chicken or egg problem arises.

Lastly, in response to the trend of energy storage interconnecting to the transmission system, featuring unique operational dispatch profiles, and co-locating with generation facilities such as solar, the NOPR seeks to memorialize the conditions under which storage is eligible for interconnection. For co-location, energy storage systems may be sited together with a resource behind a shared point of interconnection and share a single interconnection request to prevent duplicative studies. For the operational parameters, the NOPR will force energy storage operators to select and stick to specific operational behaviors. This can be memorialized in their interconnection agreement, or by providing the transmission owners with control over the system's operations and dispatch.

FERC Transmission Planning and Cost-Allocation Reforms Rulemaking

FERC also has a rulemaking to update both the *pro forma* OATT and *pro forma* Large Generator Interconnection Agreement to reform regional transmission planning, cost allocation, and generator

[161] *Improvements to Generator Interconnection Procedures and Agreements*, Federal Energy Regulatory Commission, Docket No. Rm 22-14-000 (June, 2022). Available at: https://www.ferc.gov/media/rm22-14-000.

interconnection.[162] The proposed updates most relevant to this review are (a) implementing longer regional transmission planning horizons that anticipate future resource mixes and demand forecasts and (b) identification of opportunities to "right-size" replacement and upgraded transmission facilities. The NOPR proposes to memorialize these intentions through revisions to the Large Generator Interconnection Agreement that "indicate the consideration in the regional transmission planning processes of regional transmission facilities [to] address certain interconnection-related needs."

Regional Transmission Operators

ISO New England

The Independent System Operator of New England (ISO-NE) filed a FERC-approved proposal to strategically study infrastructure needs for a cluster of remote potential renewable energy projects, mainly onshore wind, in Northern Maine.[163] This approach is particularly well-suited for interconnecting projects in Northern Maine since the system there was built for minimal load and would require significant upgrades to accommodate the large volumes of proposed renewable interconnections.

To trigger a cluster study process under the tariff, ICs must submit two or more interconnection requests within the same electrical part of the ISO-NE system based on their requested points of interconnection. To be eligible, ICs cannot have a completed system impact study at this stage. The threshold to trigger a cluster study is if the IC cannot interconnect collectively or separately unless system upgrades are installed to accommodate their facilities' capacity.

Cluster studies take part in two stages. In the first phase, ISO-NE provides detailed system information and cost estimates for the corresponding system upgrades. At this stage, other ICs may be afforded the opportunity to participate in the cluster study if they meet the eligibility criteria. The second phase involves ISO-NE conducting a "Cluster System Impact Study" to identify transmission upgrades and the corresponding *pro rata* costs for each IC.

PJM Interconnection

The Pennsylvania-New-Jersey-Maryland Interconnection (PJM) is one of the largest RTOs in the United States. It serves 65 million people, with 185 gigawatts (GW) of installed generation capacity across all or parts of 13 States.[164] Over the last two years, a backlog of over 250 GW has grown in the PJM

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162 *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, the Federal Energy Regulatory Commission, Docket No. RM21-17-000 (April 2022). Available at: https://www.ferc.gov/media/rm21-17-000.

163 FERC, Order Accepting Tariff Revisions for Interconnection Queue Clustering Revisions, Docket No. ER17-2421-000 (October 31, 2017), FERC Accepts ISO-NE Methodology for Interconnection Cluster Studies https://www.troutmanenergyreport.com/2017/11/ferc-accepts-iso-ne-methodology-interconnection-cluster-studies/ (allowing for considering interconnection requests as part of a cluster rather than individually, as well as for allocating certain network upgrade costs needed to accommodate those interconnection requests on a cluster basis, when a specified set of conditions are present in the interconnection queue).

164 PJM factsheets, https://www.pjm.com/library/fact-sheets.

Interconnection queue. This backlog has effectively stalled deployment of new solar, wind, and storage capacity proposed by ICs. In January 2023, PJM announced plans to shift to a "first-ready, first-served" interconnection review process to provide a "fast-lane" process to clear the interconnection queue backlog by 2026.[165] This approach groups proposals and assigns upgrade costs in clusters under a plan approved by the FERC.[166] The changes allow PJM to impose new requirements such as "readiness deposits," that aim to weed out more speculative projects. This requirement in particular has faced heavy opposition by some developers. PJM will also require project developers to show they have 100 percent control of the site where they plan to build their facility. External stakeholders such as the Natural Resources Defense Council and FERC Commissioner Clements support the reforms but doubt that the approach will cure the interconnection logjam absent the system transmission reforms currently proposed before the FERC, discussed below.

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165 *FERC approves PJM's 'first-ready, first-served' interconnection reform plan, steps to clear backlog* https://www.utilitydive.com/news/ferc-pjm-interconnection-reform-plan-queue/637717/, Anna Flávia Rochas (Reuters) Largest U.S. grid faces tight timeline to curb wind, solar delays, January 25, 2023,https://www.reuters.com/business/energy/largest-us-grid-faces-tight-timeline-curb-wind-solar-delays-2023-01-25/.

166 FERC, *Order Accepting Tariff Revisions Subject to Condition*, Docket No. ER22-21 10-000 (November 29, 2022), the Commission accepted changes to comprehensively reform PJM's interconnection process and adopt a "first-ready, first-served" cycle approach, subject additional compliance and informational filing requirement. The order granted the requested effective date of January 3, 2023.

Appendix C: Slide Presentations at Technical Conferences

We include the presentations from May 17, 2023 and July 19, 2023 as a separate Appendix to this report.

Appendix D: IREC Model Interconnection Procedures

In August 2023 IREC posted an updated Model Interconnection Procedures document. The former version was titled 2019 Model Interconnection Procedures. Based on IREC's information, the updated document incorporates material included in the Toolkit and Guidance for the Interconnection of Energy Storage and Solar-Plus-Storage (March 2022).

As noted throughout this report, different aspects of the IREC work is considered in the discussion of the issues. The recommendations reflect aspects of the IREC procedures, but also reflect NSPI's generally reasonable interpretation and Nova Scotia specific application of these procedures. For example, some of NSPI's cost structures are less expensive than metrics in the IREC documents; and thresholds (for example, Class 1 at 100 kW) are higher than similar thresholds referenced in the IREC documents.

We include the 2023 Edition of IREC's Model Interconnection Procedures [167] as a separate Appendix to this report.

[167] https://irecusa.org/resources/irec-model-interconnection-procedures-2023/, and https://irecusa.org/wp-content/uploads/2023/08/IREC-Model-Interconnection-Procedures-2023-FINAL-8.23.23.pdf.