

NOVA SCOTIA ENERGY BOARD

IN THE MATTER OF: THE PUBLIC UTILITIES ACT

- and -

IN THE MATTER OF: AN APPLICATION by NOVA SCOTIA POWER INCORPORATED
made pursuant to Section 3G(1) of the Electricity Act or Section
83(1) of the Public Utilities Act for approval of Changes to the
Renewable to Retail Market associated Tariffs and Terms and
Conditions

INFORMATION REQUESTS

To: **Nova Scotia Power Incorporated**
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Director, Regulatory Affairs
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By email: jennifer.power@nspower.ca

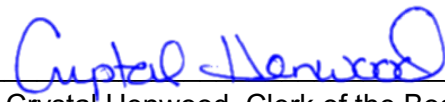
From: **Eric Borden**
Synapse Energy Economics

Responses Due: **Thursday, October 1, 2026**

Copies: 1 electronic copy (PDF searchable)

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Issued at Halifax, Nova Scotia, this 11th day of September, 2026.



Crystal Henwood, Clerk of the Board

Request IR-1:

Refer to the Application cover letter p. 2, which states “The Parties hosted a stakeholder session, led by Power Advisory, on May 14, 2026. On July 23, the Parties hosted an additional stakeholder engagement session.”

- A. Please confirm whether any party other than REI—including other prospective or existing LRSs, net metering customers, distribution-connected generation developers, or IESO Nova Scotia--participated in either session.
- B. Please provide any written comments or feedback received from attendees other than REI.
- C. If not, please explain why broader stakeholder input was not sought, given that the resulting tariffs will apply to all LRSs and RtR Customers, not solely REI.

Request IR-2:

Refer to the Application cover letter p. 4, which states “The Parties are proposing no changes to the annual cost base which underpins the pricing of EBS Tariff top-up and spill amounts as this is an issue that remains under review in accordance with the Board’s direction in the Company’s 2026 AAR Application (M12551) and is subject to change.”

- A. Please explain the interrelationship between this Application and the Board’s ongoing review of the EBS Tariff pricing in NS Power’s 2026 AAR Application (M12551).
- B. How does NS Power propose to coordinate the two proceedings to avoid inconsistent outcomes?

Request IR-3:

Refer to the Attachment 2 Appendix section, pp. 30-39. The jurisdictional scan shows approaches to charging distribution-connected generation for grid use ranging from no charge (most of Canada) to fixed monthly account-related charges (e.g., Ontario, roughly \$87-\$266/month) to per-MW system-operator contribution charges (e.g., Alberta: \$10,000-\$50,000/MW).

- A. Please explain how the proposed DAS Tariff’s administration-only charge was benchmarked against these comparators.
- B. Please explain whether NS Power anticipates proposing a distinct distribution-use charge (above administration-only) in the future, and under what circumstances.
 - i. What data will be collected to inform the development of these charges?

Request IR-4:

Refer to Attachment 3, p. 8, which notes that, unlike NS Power’s net metering construct, there is no prohibition on RtR distribution-connected generation exceeding load.

- A. Please describe any analysis NS Power has undertaken, or intends to undertake, of the potential for reverse power flow, feeder overloading, or protection coordination issues arising from this design choice.
- B. Please identify what interconnection study thresholds or triggers would prompt further technical review.

1
2 **Request IR-5:**

3 Refer to Attachment 4, p. 1, which states "Customer exports will be tracked and reported to the
4 LRS to support the LRS' commercial arrangement with the LRS' customer and will serve as an
5 input to the generation amount applicable to the LRS under the Standby Service, Energy
6 Balancing Service and RTR Transition tariffs."

- 7 A. Please confirm that customer exports are a proxy for total behind the meter generation
8 of a resource.
- 9 B. Why is self-consumption (generation consumed by on-site load) not incorporated into the
10 generation total for a BTM resource? In other words, if some generation is consumed
11 on-site, shouldn't this generation amount accrue to LRS entity? Please explain.
- 12 C. Has NS Power considered use of production meters to measure generation of BTM
13 resources? Why or why not? Could LRS entities install production meters to measure
14 generation of BTM resources?

15
16 **Request IR-6:**

17 Refer to Attachment 4, p. 1, which states, "The LRS' Customers and generators will make all
18 necessary arrangements to ensure that their generation and load do not unduly deteriorate the
19 integrity of the power supply system, either by its design and/or operation. These specific
20 requirements shall be stipulated by way of a written operating agreement."

- 21
22 A. Please describe and define what is meant by "necessary arrangements."
- 23 B. Will written operating agreements be approved by the Board?
- 24 C. Is there a dispute process to resolve disagreements about the written operating
25 agreements, and if so, what is it?
- 26 D. Please describe and define what is meant by "unduly deteriorate." For example, if there
27 is a temporary power quality issue does this qualify, but if not, what does? Please
28 explain.
- 29 E. What is the process if there is a dispute between an LRS and NS Power regarding what
30 constitutes a "necessary arrangement?" Where is this described or laid out?
- 31 F. Shouldn't power system issues due to generation be addressed in the interconnection
32 process? Please explain the interplay between this clause and interconnection studies
33 accomplished by NS Power, if any.
- 34 G. Please provide references and a brief explanation of the interconnection process for
35 different sized systems to NS Power's distribution system.
- 36 H. Please explain the process if power system issues occur after a generator has
37 interconnected to the system.
- 38 I. Please state whether any distribution-level costs caused by distribution-connected
39 generation (e.g., incremental losses, voltage management) are being recovered from
40 any customer class prior to the post-2028 review, and if so, from which class(es). Please
41 provide a citation to the amount of these costs over the last five years.

42
43
44 **Request IR-7:**

1 Refer to Attachment 4, pp. 2-3.

- 2
- 3 A. Please provide NS Power's current estimate of forecast administration costs underlying
- 4 the DAS Administration Charge, broken down by cost category (e.g.,
- 5 metering/settlement systems, IT, incremental labor), together with the assumed "forecast
- 6 number of LRS' subscribed" denominator.
- 7 B. Please also explain how the charge would be calculated if, initially, only one LRS (i.e.,
- 8 REI) is subscribed to the service.
- 9 C. Please confirm whether the DAS Administration Charge is intended to recover only costs
- 10 incremental to the aggregation / export-tracking function, or whether it also recovers
- 11 costs already embedded in the Distribution Tariff rates paid by the RtR Customer for
- 12 Distribution System Access. Explain the safeguard against double-recovery of the same
- 13 cost between the two tariffs.

14

15

16 **Request IR-8:**

17 Refer to Attachment 4, p. 3, which states "In light of the early stages of RtR market development

18 in general and, in particular, Distribution connected Generation market development following

19 2028, a review of the operation of this tariff and the broader RtR construct will be undertaken by

20 NS Power and submitted to the Board for its review." Please also refer to Attachment 3, p.4,

21 which states that "REI expects to enter the market December 1, 2026, and complete entrance

22 by COD date for Mersy Wind, Q1 2027."

- 23 A. Please provide the expected timeline and process for the 2028 review referenced in the
- 24 DAS Tariff Review section, including whether stakeholders including REI will have an
- 25 opportunity for input.
- 26 B. Please describe the specific data NS Power intends to collect over the interim period to
- 27 inform its review of the tariff.
- 28 C. Please explain why an approximately two-year period was selected given REI's stated
- 29 intention to enter the market by December 1, 2026 and to have distribution-connected
- 30 generation online by 2027.
- 31 D. Will LRS entities be held responsible for costs incurred before the development of
- 32 charges associated with RtR market? If so, when and how will these costs be collected?
- 33

34 **Request IR-9:**

35 Refer to Attachment 5, p. 2, which describes the Energy Balancing Service Tariff's top-up and

36 spill quantities as adjusted by "transmission losses" and "transmission locational losses, as

37 applicable to the geographic zone in which the generating facility is interconnected."

- 38 A. Please clarify how this loss adjustment applies (or does not apply) to a Distribution-
- 39 connected Generation facility that has no transmission zone designation, and identify
- 40 what loss factor, if any, is applied to such a facility's output in the top-up/spill calculation.

41

42 **Request IR-10:**

43 Refer to Attachment 5, p. 2, and Attachment 7, p. 2. The EBS and Standby Service

44 Administration Charges are each set at \$414.63 per month.

- 1 A. Please confirm that an LRS taking either service must also take the other.
2 B. Please explain how double-counting of shared administrative costs (e.g., account
3 management) is avoided across the two charges.

4
5 **Request IR-11:**

6 Refer to Attachment 5, p. 3.

- 7 A. Please explain the rationale for excluding fixed cost adder from the spill credit.
8 B. Please confirm whether the energy charge components listed in Attachment 5 reflect any
9 incremental costs of system benefits (e.g., reduced losses) attributable specifically to
10 distribution-connected generation. If not, indicate when such effects are expected to be
11 studied and potentially reflected in rates.

12
13 **Request IR-12:**

14 Refer to Attachment 6, pp. 10-11, Section 11.

- 15 A. Please confirm that Distribution Tariff energy and demand charges apply only to the RtR
16 Customer's metered imports (exports excluded).
17 B. Please explain who bears any incremental distribution system costs associated with
18 accommodating bidirectional flows at RtR Customer premises (e.g., feeder upgrades,
19 protection equipment, voltage regulation costs attributable to distribution-connected
20 generation).

21
22 **Request IR-13:**

23 Refer to Attachment 6, Section 11.3 and Attachment 8, Section 15.4.1. The Distribution Tariff
24 states that Real Power Losses are incorporated into Distribution Tariff rates and that the RtR
25 Customer is responsible for such losses, and the LRS Terms and Conditions provide that RtR
26 Customer load (imports) is adjusted for distribution losses using established average annual
27 rate class losses.

- 28 A. Please confirm whether an equivalent, symmetric loss adjustment is applied to
29 distribution-connected generation exports.
30 B. If not, quantify the potential for under- or over-recovery of system costs this asymmetry
31 could create.

32
33 **Request IR-14:**

34 Refer to Attachment 7, pp. 2-5.

- 35 A. Please describe how the Effective Load Carrying Capability (ELCC) methodology will be
36 applied in practice to small (1-5 MW), potentially non-dispatchable, distribution-
37 connected renewable resources, including: (1) The granularity (system-wide, zonal, or
38 feeder-level) at which ELCC values will be determined, and (2) Whether/how an LRS
39 may challenge or seek reconsideration of an assigned ELCC value.
40 B. Please provide a numerical example of the Monthly Standby Contract Demand (MSCD)
41 calculation for a hypothetical LRS with a mix of BTM customer-owned generation and
42 contracted distribution-connected generation, showing how CMPFD, CMDAFi, CCI,

1 GCi, and PR interact. Confirm how the "exports only" treatment of surplus purchased
2 from Distribution-connected Generation customers is incorporated into GCi.

- 3 C. Please explain the rationale for the failure-to-deliver remedy in Special Condition (6)
4 (payment of NS Power's cost to procure or self-supply undelivered capacity, net of
5 charges already paid), including whether any cap, force majeure exclusion, or liquidated-
6 damages treatment applies, and how this remedy compares to the equivalent default
7 provisions in the Wholesale Market BUTU Tariff.
8

9 **Request IR-15:**

10 Refer to Attachment 8, pp. 16-17, Section 14.1.2.

- 11 A. Please provide an estimate of the total incremental cost involved with AMI metering
12 necessary to interconnect a generator to the distribution system.
13 B. Please clarify how the incremental AMI metering and communications costs required to
14 separate hourly import and export channels are recovered (e.g., through general
15 distribution rates, through the DAS Administration Charge, or as an incremental metering
16 charge to the RtR Customer, under LRS Terms and Conditions?)
17

18 **Request IR-16:**

19 Refer to Attachment 10, redlined language for the definition of "Distribution System Access."

- 20 A. Do these changes have any implications for cost allocation? Please explain.
21

22 **Request IR-17:**

23 Refer to Attachment 11, pp. 4-5, Condition 5 and sub-parts.

- 24 A. Please describe the process and timeline by which an LRS is expected to "demonstrate"
25 compliance with items (i) through (vi) to NS Power's satisfaction.
26 B. Are these standards expected to be met prior to operation or during? Please explain.
27 C. Is there a right of appeal or independent review if NS Power determines the LRS has not
28 met this standard? Please explain.
29 D. Regarding part (iii) how are "critical times of the year" determined? Does this refer to a
30 specific type of event?
31 E. Are these conditions appropriate for a small-scale resource like BTM solar? Please
32 confirm that a BTM resource could not generally meet these conditions, or what NS
33 Power's expectation is for smaller, BTM resources.
34 F. Would it be more appropriate for these conditions to apply to larger and/or FTM
35 distribution-connected resources? Why or why not?
36 G. If a capacity contribution factor for a BTM resource is zero, will it still be incorporated into
37 NS Power resource planning?
38

39 **Request IR-18:**

40 Refer to Attachment 12, p. 12, Section 9.8.

- 41 A. Please provide the specific language in the Electricity Act referenced.

- 1 B. Why would a customer be “de-rated?” How would this, in practice, be accomplished?
2 Please provide an illustrative example of a customer who is de-rated and how this impacts
3 the customer’s bills, as well as any other consequences of de-rating.
4 C. What recourse, if any, would a customer have if they were not adequately informed of the
5 de-rating risk by the LRS?
6 D. What constitutes whether an LRS has “informed” a customer of this provision?
7

8 **Request IR-19:**

9 Refer to Attachment 12, p. 16, Section 13.

- 10 A. Please clarify how a distribution-connected generator sized above net-metering limits will
11 be technically evaluated for interconnection. Please also describe what protections exist
12 against adverse impacts on feeder capacity or other customers served on the same
13 feeder.
14 B. Regarding the sentence that states “For clarity, sizing limits applicable to NS Power’s net
15 metering programs do not apply.” Please explain this sentence.
16 i. Do the sizing limits not apply to both BTM and FTM resources?
17 C. Please confirm there is no maximum energy or capacity amount an RtR Customer or
18 LRS may interconnect.
19

20 **Request IR-20:**

21 Refer to the 2026 NS Power Load Forecast Report, Section 4.8. Specifically, refer to lines 11-12,
22 which states “The peak forecast remains unchanged as NS Power is required to serve the full
23 peak of these customers if needed.”

- 24 A. Please explain how the peak contribution of RtR resources will be accounted for in NS
25 Power’s planning to meet peak load.
26 B. Will the contribution of RtR resources in meeting peak load reduce NS Power’s capacity
27 needs? Please explain.
28 C. Please explain how this influences cost allocation.
29