Attachment

NS Power Responses to Stakeholder Comments: Assumptions/Modeling Scenarios/Early Insights

Theme	Stakeholder	Comment	NS Power Response
Wind Capital Cost Assumptions	SWEB Development	On slide 16 of the Assumptions and Analysis, is the NSPI Proposed Evergreen input the cost per MW to build new wind energy projects for NSPI? For greater context, a review of the NSPI interconnection queue shows that there are several projects whose network upgrade costs are less than $15,000,000 for 230 kV interconnections. Some of these proposed projects have capacities of approximately 100 MW. Given that the forecasted upgrade costs are the only capital costs incurred by NSPI to realize a project of this size via the Nova Scotia Rate-Base Program Request for Proposals (NS RBP RFP), should the IRP assumptions include a "Competitive Wind RFP Integration" option or similar that reflects the low capital expenditure and operational expenditure values payable by NSPI and potentially the actual bid proposal prices of the NS RBP RFP winners for the LCOE assumptions?	NS Power will model new wind procured via the Rate Base Procurement (RBP) as a PPA, with a flat price of $53/MW in the initial scenarios. The RBP additions (assumed 350MW wind) will be fixed and included in all scenarios. This cost is assumed to include all cost to bring the PPA into service including interconnection costs and network upgrades associated with each project. To maintain consistency within the model, NS Power will offer new wind as a candidate resource based on capital and operating cost estimates. Under both representations, the full resource cost is allocated to the project and considered in the partial revenue requirement of the IRP model.
Atlantic Loop Assumptions	SWEB Development	Could NSPI provide more clarity on energy rate assumptions for the Atlantic Loop?	NS Power is using S&P Global's latest fundamental long-term forecasting service, which estimates the monthly price of energy for both On and Off Peak for the NEPOOL market. These estimates are adjusted to reflect foreign exchange assumptions

			and impacts of transmission tariffs to create a landed Nova Scotia based price assumption.
NS Power ECEI Wind Project	SWEB Development	Could NSPI provide details on the 160 MW wind ECEI project being modelled as operational in 2025?	The 160 MW ECEI wind project is undergoing early feasibility studies with a projected in service date of 2025. The project is listed in the 2022 ACE Plan as a subsequent submittal project.
Renewable + Energy Storage Option	SWEB Development	Has NSPI considered adding a Renewable + Energy Storage option to increase the Effective Load Carrying Capability (ELCC) of these resources?	The capacity expansion model is able to select combinations of renewable generators and energy storage when optimal to meet system needs. The respective contribution of each resource to PRM will be reflective of their marginal ELCC as calculated in the 2020 IRP capacity value study (E3). NS Power is considering approaches to incorporating the incremental diversity benefits to ELCC of pairing renewables with storage (see Section 4.3.5 of the 2020 IRP Capacity Value Study). While NS Power's IRP capacity expansion model will select battery storage and renewable resources independently, this does not preclude combining these resources into a hybrid project if both resources are selected and key services can be maintained (e.g. locational benefits).
Operational Life for Renewables – Proposed to Extend	SWEB Development	Based on SWEB's experience in other renewable energy markets, operating life for solar photovoltaic (PV) projects should be 35 years. For wind energy projects, SWEB suggests an assumption of 30-year operational terms.	NS Power has used publicly available source information to support its assumptions. If SWEB can provide publicly available support for its proposed changes in assumptions, NS Power will consider those. Alternatively, the Low Cost Battery Storage/ Low Cost Renewables scenario could serve as a proxy for a longer life, as either method results in

			improved economics of this resource vis-à-vis other candidate resources.
LCOE Assumptions – NSPI Intent to Continuously Update	SWEB Development	With respect to the assumed LCOE, will NSPI continue to update these assumptions based on the continued rise in capital expenditure costs for energy projects? The recent NS RBP RFP will provide valuable contemporary LCOE information for certain renewable energy technologies, however NSPI should be cautious if applying these results to the LCOE assumptions in the IRP without adjusting the LCOEs for other supply technologies given the status quo assumptions would not necessarily be based on current market pricing, which is particularly relevant current trends of rising commodity pricing.	NS Power intends to proceed with the modeling assumptions finalized during this process for the 2022 modeling work.
Fuel Pricing Forecast	SWEB Development	SWEB encourages NSPI to use contemporary fuel pricing forecasts (published in 2022) when performing the modelling for the present IRP.	NS Power's forecasts are based on contemporary data (June 2022) from NS Power's fuel pricing providers. NS Power has added the dates of fuel forecast source data to the Final Assumptions to clarify.
LCOE of Solar Tracking	SWEB Development	Can it be assumed that the LCOE of solar tracking is equivalent that of offshore wind in 2022- 2024?	The LCOE of offshore wind, assuming a 'low' capital cost sensitivity and 45% capacity factor, has a comparable LCOE of the 'Base' solar assumptions early in the period (2022-2024). As per Slide 20, solar is forecast to have a steeper cost decline trajectory, which serves to widen the LCOEs between technologies over the mid and the end of the planning horizon.
Solar PV Cost Assumptions	SWEB Development	Could the IRP assumptions be updated to include other common solar PV configurations such as ground-mounted systems with bifacial panels/modules?	NS Power's Resource Options Study, as part of the 2020 Pre-IRP Deliverables, considered this. The following is an excerpt:

			- Utility-scale projects are now almost exclusively single-axis tracking - Tracking solar provides increased capacity factor for little to no premium in capital costs - Only tracking solar considered NS Power's objective is to develop a range of input assumptions reflective of potential projects in Nova Scotia, without testing specific configurations. If SWEB has references to utility scale projects based on alternative configurations that have superior economics to the Base and Low range currently proposed to be modeled, NS Power would appreciate and consider the information.
Community Shared Solar Programs – Considered in Modelling Work	SWEB Development	Is the IRP assumptions list appropriately addressing the expected community shared solar program (or equivalent) and its potential impact on the future DER projections?	The 2022 Load Forecast, extended to 2050, serves as the base load forecast for the 2022 Evergreen IRP. This forecast includes forecast DER adoption over the planning horizon. To assess the impact of higher than forecast DER penetrations, NS Power also proposed a High DER sensitivity. Please see Slide 24 of the Draft Evergreen Assumptions. This level of DER penetration (up to 1500MW) would represent among the highest known penetrations of DER on a pro-rata basis (total MW of DER as a percentage of system peak).
Domestic Renewables	SWEB Development	SWEB suggests that there be some evaluation of the benefits of domestic energy supply by way of new renewable generation and associated storage projects. As evidenced in the recent NS RBP RFP requirements (i.e. partnerships, economic benefits, local labor content, etc.), there is significant value provided to NS by having more domestic supply given its contribution to direct and indirect economic	The focus of NS Power's IRP process is to understand the electricity system revenue requirement differentials between alternative resource plans. Other potential benefits outside the electricity system are not considered in the analysis. NS Power is able to qualitatively examine energy security implications of various resource plans as

		benefits from the creation of jobs, supply chain development, and municipal and provincial taxes. Further, domestic energy supply or generation from renewable energy resources can further augment NS's energy security by increasing the availability of non-emitting energy resources that are located within the province and that which do not require sub-sea transmission.	part of examining model outputs; comments from stakeholders in this regard are welcome during the modeling results review stage.
Inclusion of PHP Wind Project	Port Hawkesbury Paper (PHP)	Assumptions Slide 10 – Rate Base Procurement and PHP Wind Project In addition to the Rate Base Procurement, PHP has been developing a separate wind project at Pirate Harbour to meet approximately one-third of PHP's load. This project has been under development for a number of years and continues to progress. The most updated plan assumes a project size of 130MW to be in service Q4 2025. Considering the size and timing of the project, consistent with the treatment of the Rate Based Procurement Program, the IRP Modeling should also assume an additional 130MW of wind in service by 2025 on account of this PHP project.	As shown in the Early Insights modeling results, it is anticipated that many of the modeling scenarios will include additional economic buildouts of variable renewable resources (including wind) to meet the RES and carbon constraints in the evergreen model. It is reasonable to assume that some of this new wind could come from the identified Pirate Harbour project, if constructed.
Modeling of the Federal Backstop – Request to Model Lower Carbon Pricing	Port Hawkesbury Paper (PHP)	Assumptions Slide 11 – Federal Carbon Price Framework (OBPS) Slide 11 of the Draft Assumptions states: "Since Provincial carbon policy for 2023+ has yet to be determined, NS Power proposes to model the Federal Backstop carbon pricing mechanism as	With the Provincial carbon policy currently in development, the Federal Backstop is the only carbon pricing mechanism currently defined sufficiently for modeling purposes. Although the Provincial carbon policy may not follow the OBPS mechanism directly, any Provincial carbon policy plan must demonstrate they are

		prescribed by the Output Based Pricing System (OBPS)." As NS Power is aware, the Federal Backstop is a fallback option, as "[t]he Government's approach to pricing carbon pollution gives provinces and territories the flexibility to implement the type of system that makes sense for their circumstances as long as they align with minimum national stringency standards, or 'benchmark' criteria."2 During the 2018-2022 time period, Nova Scotia implemented a cap-and-trade system which the Province estimated would "…increase electricity rates by about 1%, versus about 8% by 2022 under the federal plan."3 The Federal Backstop should be understood as representing a "highest case" $/tonne price of carbon during the Planning Period to 2050. Accordingly, at a minimum NS Power's Evergreen IRP Update should model sensitivities using a carbon price that is lower than the Federal Backstop to determine whether and how changes to this assumption would alter the trajectory of the analysis and results.	meeting the outcomes of OBPS. Given that, modeling lower carbon pricing without a framework for justification may produce results that are not reflective of outcomes that can be supported by the Federal backstop requirements.
Capital Cost Estimate and LCOE Basis	Port Hawkesbury Paper (PHP)	Assumptions Slides 16 and 20 – Capital Cost Estimates ($/KW) and Levelized Cost of Energy – Renewables Slide 16 of the Draft Assumptions shows a Proposed Evergreen Input Assumption of $1,772/KW (2022$) for onshore Wind, which is significantly lower than the 2020 IRP Estimate of $2,100/KW (2022$). Slide 20 of the Draft Assumptions shows a levelized cost of onshore	The capital cost estimates are a reflection of publicly available data; a range of cost estimates are provided in the Assumptions with citations to each source. For supply side resources, in the case where multiple public sources were identified, NS Power is using the mid-point value as the assumption. The LCOE's provided are real dollar values. An equivalent nominal dollar LCOE, using NS Power's capital cost estimate of 1772/kW results in a 2022 LCOE of $53/MWh.

		Windstarting in the mid-$40s/MWh, and a low-cost case starting below $40/MWh. NS Power should provide further justification and support to explain the development of these assumptions, which appear on the low end of what may be feasible.	
Import Pricing	Port Hawkesbury Paper (PHP)	Assumptions Slide 33 – Atlantic Loop Assumptions Slide 33 of the Draft Assumptions states that the Energy and Capacity Cost of the Atlantic Loop will be: "Based on updated NE market forecast, adjusted to represent Quebec import source." NS Power should provide the details of these forecasts to IRP stakeholders (on a confidential basis if required) that clearly shows the nature of the adjustments made "to represent Quebec import source."	NS Power's fuel and market price assumptions are developed from commercial forecast products and as such are not able to be shared via the IRP Evergreen process.
RES Compliance Status – Imports	Port Hawkesbury Paper (PHP)	Assumptions Slide 34 – Other Regional Import Assumptions Slide 34 of the Draft Assumptions states that energy from New England "will not be RES compliant." Given the fact that at least a portion of the energy from New England would be expected to come from renewable resources, NS Power should provide a more detailed explanation why all Atlantic Loop energy is forecast to be RES compliant as compared to none of the New England energy.	To ensure RES compliance from the New England market, NS Power would have to contract with a single counterparty (or counterparties) with dispatchable renewable energy. While this could be possible, it is more likely that capacity and energy would be contracted from the market, which includes a mix of traditional and renewable generators. The RES regulations currently do not recognize blended products as contributing to meeting RES requirements; this is similar to NS Power's treatment of imports from New Brunswick.
Wind Integration Requirements – Curtailment	Port Hawkesbury Paper (PHP)	Assumptions Slides 49-50 – Renewable Integration Updated 2022 Evergreen IRP Approach	At the start of the modeling horizon (2025), NS Power is assuming 200MW (800MWh) of in-service battery energy storage system(s). This, when

		Slide 49 of the Draft Assumptions states: "NS Power has considered the input from stakeholders relating to the 2020 IRP integration methodology and has refined this constraint for the 2022 Evergreen IRP." PHP supports the changes to this constraint as compared to the 2020 IRP, but believes it would be helpful to all stakeholders if NS Power provided a more detailed explanation of exactly how the model will address the instantaneous curtailment of wind, particularly in advance of the reliability tie and any domestic integration assets. The addition of 350MW from the Rate Base Procurement Program to the current system, together with PHP's 130MW wind project and NS Power's proposed ECEI wind project of 160MW, would result in significant amounts of wind above the "max hourly dispatch constraint of 700MW". The IRP modeling analysis and results should clearly identify the % of wind energy that could be subject to instantaneous curtailment as a result of this input assumption across all scenarios, how such instantaneous curtailment would be applied to the various wind projects, and what the potential consequences of this instantaneous curtailment could be on the economics of those projects. Similarly, the IRP modeling analysis and results should clearly identify the % of wind energy that could be subject to curtailment due to the maximum instantaneous penetration	paired with a 200MVA Synchronous Condenser, facilitates 400MW of incremental instantaneous wind dispatch (or up to 1100MW total wind dispatch in any given hour). With the near-term wind additions described in the assumptions, and including the potential Pirate Harbour project, total installed wind would equate to 1240MW. Thus, curtailment due to the instantaneous constraint would be expected to be very low and constrained to the times when all wind shapes are at or near their highest output. In 2027, the Reliability Tie is assumed to be in-service, facilitating an additional 500MW of wind dispatch potential (or up to 1600MW total in any hour). NS Power agrees it would be helpful to provide an analysis on the amount of wind curtailment seen in each scenario as an output of the Evergreen modeling. The most recent update on NS Power's Wind Integration Studies was provided during the April 2022 IRP Action Plan workshop.

		constraint across all scenarios, particularly in the 2025-2030 time period when this assumption is set at 70% and the potential timing of the reliability tie and domestic integration assets is less certain. The manner in which this constraint would be applied to the various wind projects, and the potential consequences on the economics of those projects, should also be specifically identified and commented on as part of the modeling analysis and results. In this regard, PHP notes that the 2022 10 Year System Outlook Report recently filed by NS Power on June 30, 2022 states in footnote 22 that "…verification of wind integration strategies via additional system studies will be completed as part of the IRP Action Plan." It would be helpful if NS Power could specifically identify the "additional system studies" that are currently underway or under consideration to inform the issue of wind integration.	
ECEI Projects	Port Hawkesbury Paper (PHP)	Slide 7 of the Draft Modeling Scenarios states: "The "early insights" PLEXOS run outcome includes many of the evergreen IRP proposed assumptions: - Carbon Policy Updates (2030 RES/Coal Retirement, Output Based Pricing and Federal Carbon Price) - Atlantic Loop, RBP+NSP Wind, 200MW BESS, C2G Conversion, and Reliability Tie are included in this scenario…" (emphasis added)	The four ECEI projects, as identified in the 2022 ACE Plan, will be included in all scenarios. These projects are consistent with the 2020 IRP results and its associated Action Plan and Roadmap. Modeled costs of these resources will be per the assumptions provided in the IRP Evergreen Assumptions materials. All projects identified as part of the ECEI program will be subject to economic analysis in support of their application. The UARB, in its decision on the 2022 ACE Plan, acknowledged the basis for the ECEI projects while indicating that economic justification

		It is not clear from the Draft Assumptions and Modeling Scenarios slides whether NS Power intends to add its ECEI projects as inputs to the model that will be included in all scenarios, or whether NS Power's ECEI projects will be subject to economic selection by the model in a similar manner to other potential capital additions. PHP notes that at page 15 of the 2022 10 Year System Outlook, NS Power's "updated resource plan" includes "Eastern Clean Energy Initiative (ECEI) capital investments as described in the Company's 2022 Annual Capital Expenditure (ACE) Plan (M10366)." In its Closing Submission in that case, NS Power stated at page 11 that: "As further stated within NS Power's Rebuttal Evidence, the purpose of the IRP is not to prescribe specific investments, such as the ECEI projects." As part of the Evergreen IRP, NS Power should specifically clarify the manner in which the ECEI projects will be considered and modeled, as well as the specific assumptions underlying these new capital projects, which have not yet been the subject of NS Power capital applications to the Nova Scotia Utility and Review Board.	on a project-by-project basis will be required to support future applications for approval.
Testing the Delay of the Atlantic Loop	Heritage Gas	Regional Integration Heritage Gas understands that NSP has modelled the Atlantic Loop regional integration project as a key driver for scenario analysis. As noted in the Draft Assumptions deck, this is assumed to act as a generation source for the province for up to 550 MW of capacity and firm energy import	The Atlantic Loop will be modeled via an "in/out" analysis, with an in-service date of 2030 in the majority of scenarios being modeled, reflective of the targets in the Atlantic Clean Power Roadmap. Based on feedback received on the Draft Assumptions and Scenarios, NS Power has added a sensitivity to the base "with Atlantic Loop" scenario (2035 net zero, current policy and trends load

		under long-term contracts via new transmission lines (slide 31). Considering the cost and energy magnitude of the Atlantic Loop project, and the discussion that took place around the June Workshop, Heritage Gas recommends as follows: - That NSP include its modeling sensitivity analyses that incorporate alternative in-service dates that extend beyond the current 2030 target	forecast) with an Atlantic Loop availability date of 2035 to understand potential impacts of this alternate date.
New England Import Assumptions	Heritage Gas	Heritage Gas understands that access to a further 120MW of firm energy may be available from a second 345 kV AC line to Salisbury and a further extension to Coleson's Cove, in order to provide for Firm Energy imports. We further understand that the Reliability Tie will be included in all scenarios, and modelled with an in-service date of 2027 (slide 32). Heritage Gas seeks clarification from NSP on the following items relating to the Reliability Tie and the additional 120MW: - What steps have been taken, and/or what steps will need to be taken, in order to secure the 120 MWs of Firm Energy imports referred to at slide 31? - Have any counterparties been identified for the firm energy, and if so, what is the status of commercial negotiations with any such counterparty(ies)?	The potential availability of 120MW from a transmission expansion to the Coleson Cove area is a modeling assumption for use in the 2022 Evergreen IRP and is consistent with the Regional Integration assumptions used in the 2020 IRP analysis. The assumption of reduced availability of firm capacity from a New England import source was discussed in NS Power's 2021 IRP Action Plan update, based on recent ISO-NE Regional System Plan documents. This 120MW assumed for modeling purposes is not under commercial discussion at this time; if it is found to be a component of low-cost scenarios in the Evergreen IRP analysis, pursuit of such an import could be added to NS Power's updated IRP Action Plan.

		- How does the extension to Coleson's Cove allow for an additional 120MW of Firm Energy Imports - Has NB Power included the 120 MW extension project in their planning forecasts? - Given the challenges that have been experienced in recent years with building new infrastructure projects spanning multiple jurisdictions, which require broad stakeholder consultations, should NSP's analysis include scenarios where this project is delayed, or does not proceed?	
DSM Scenario Updates	E1	The most recent Demand Side Management (DSM) Potential Study was completed in 2019 as an input for the 2020 IRP. In response to discussion at the June 27, 2022 stakeholder workshop, E1 is proposing to provide the following modified Potential Study scenarios as prepared by Guidehouse (formerly Navigant): - Base+ – a new scenario designed to sit roughly halfway between Base- and Mid-DSM investment and savings levels; and - Modified Mid – the Mid scenario will be adjusted to introduce a three-year ramp of activities from E1's 2023-2025 Settlement Plan levels (as filed on March 11, 2022) to Mid scenario levels. Results in the outer years of the study may also be impacted by this adjustment because the delayed uptake	NS Power appreciates E1 providing a modified Mid scenario to introduce a three-year ramp of activities from the Settlement Plan to the 2025+ forecast and the Base+ scenario. Receipt of the adjusted Mid scenario by August 8th aligns with the evergreen IRP process timing and the new profiles will be reviewed by NS Power at that time. NS Power has proposed additional sensitivities in the updated Modeling Scenario plan that include the modified DSM scenarios, which will be provided by E1 (Modified Mid, Base+).

		in early years will leave more potential in later years. E1 is not proposing any changes to any of the other Potential Study scenarios. The modified scenarios will be available for input to the 2022 IRP Update modelling by August 8, 2022. The intent of the modified scenarios is to account for the proposed levels of DSM in E1's 2023-2025 Settlement Plan and provide a ramp to Mid-DSM from these levels that reflects a smoother trajectory that is more operationally realistic.	
Timing of Future IRP Updates	E1	To ensure current Potential Studies and/or Potential Study updates are available when required as an input for future Evergreen IRP processes, while minimizing costs, E1 requests that NS Power provide responses to the following questions: - What frequency will IRP updates/refreshes be conducted (i.e. is NS Power currently planning on conducting an IRP Update or refresh in 2023? In 2024?)? - When will the next full IRP analysis be considered? For future IRP updates/refreshes, E1 requests that NS Power commit to providing E1 a minimum of six (6) months' notice prior to an IRP update, and a minimum of twelve (12) months' notice prior to a full IRP process to provide E1 sufficient time to prepare the most accurate and up-to-date information possible.	As referenced in IRP Roadmap Item 8 (Evergreen IRP), NS Power will provide an update to stakeholders on the Action Plan and Roadmap on an annual basis. Similar to this year, the update summary provided to stakeholders will act as a signal to both the timing and the nature of the work and/or updates that will occur in that given year (i.e. if an evergreen modeling exercise is required, which may warrant the need for additional information from E1). NS Power had reached out to E1 in advance of determining that an evergreen update would take place in 2022 to understand if E1 wished NS Power to make adjustments to the DSM Potential Study assumptions. NS Power anticipates continuing to engage collaboratively respecting future evergreen exercises. The timing and need for full IRPs are determined in the discretion of the UARB in this jurisdiction. For the 2020 IRP, the UARB provided direction to E1 respecting its timing and engagement expectations

			for the completion of its Potential Study. NS Power assumes a similar process would occur if a new full IRP were to be directed.
Additional DSM Sensitivities	E1	Relative to the 2020 IRP, the 2022 IRP Update faces additional decarbonization and electrification requirements, higher fuel prices, and continued uncertainty around the Atlantic Loop and the availability of firm imports. These factors suggest that additional DSM, beyond the Base-DSM level, may be desirable. NS Power has proposed only one Mid-DSM sensitivity to be paired with Net Zero 2035, current electrification policy, and trends and the Atlantic Loop (CE1-E1-R1). While this is a useful sensitivity, E1 recommends that additional DSM sensitivities be explored. The following additional scenarios have been proposed: CE1-E1-R2 – modified Mid CE1-E2-R2 – modified Mid CE2-E1-R1 – modified Mid	NS Power has proposed in the updated modeling plan additional DSM.
Avoided Costs	E1	E1 continues to assert that a key output of any IRP update is updated DSM avoided costs. E1 requests that the 2022 Evergreen IRP Update process include the production of updated avoided costs of DSM associated with, at minimum, the highest performing candidate resource plan. E1 also notes that NS Power did not directly produce avoided costs of capacity applicable to	NS Power will have the models available to calculate avoided costs for specific use cases if required in the future. Similar to the 2020 IRP, the avoided costs will be calculated by NS Power but is not part of the Evergreen IRP scope. NS Power can provide this information to E1 following the conclusion of the Evergreen IRP work for 2022.

		demand response in the 2020 IRP because the "No-DSM" case included some demand response. E1 has been using these avoided capacity costs for demand response planning; however, this may be undervaluing demand response resulting in cost-effectiveness challenges in demand response implementation. E1 recommends that this issue be addressed as part of the generation of updated avoided costs of DSM through the 2022 Evergreen IRP Update process.	
Financial Assumptions	E1	The 2019 DSM Potential Study used a 2% inflation rate to produce nominal investment amounts in any given year and relied on a 2019 base year for the purposes of calculating nominal amounts. Care should be taken to ensure any incremental inflation assumptions above 2% are properly applied. E1 requests that NS Power provide the adjusted DSM cost streams to E1 with all formulas intact.	NS Power will provide calculations to E1 with formula intact.
Planning Horizon	E1	NS Power has selected a preliminary study period of 2025 to 2050. Selecting an update study period three years into the future limits near-term findings and results. In particular, this prevents NS Power from being able to update avoided costs of DSM for 2023 and 2024, which are used by E1 in its Rate and Bill Impact Analysis, DSM planning, internal program uses, as well as DSM Potential Studies. Beyond avoided costs of DSM, there is value in providing updated results more generally – the 2020 IRP Action Plan has a short-term focus. Losing the first two years from the front-end of	Integrated Resource Plans, and any additional updates, are long-term planning studies. The starting period of the planning horizon reflects the earliest period when additions to the generation fleet could be possible. NS Power has other processes that will serve to assess near-term forecasts.

		the analysis would limit the available short-term findings from the 2022 Evergreen IRP Update exercise and any associated IRP Action Plan. E1 recommends including 2023 and 2024 in the 2022 Evergreen IRP Update study period.	
Load Assumptions	E1	The hybrid-peak mitigation approach is a new concept for electrification introduced as part of the 2022 Evergreen IRP Update process. NS Power should better explain the assumptions relating to this scenario, and how it differs from the "Current Policy and Trends" scenario. In particular: - What portion of customers are assumed to retain their existing heating source, and what is the assumed mix of back-up heating sources? - Does the analysis include any fuel sources, or significant volumes of fuel, that would conflict with existing legislation? - How the "Hybrid Peak Mitigation" electrification forecast relates to the assumptions in NS Power's 2022 Load Forecast. Does the "Hybrid Peak Mitigation" scenario remove the "NS Power HP Peak (MW)" peak impact, the "E3 HP Peak (MW)" peak impact[2], or does it assume a different impact? Please explain.	The hybrid peak mitigation scenario is reflective of a mix of heating sources (both heat pump adoption and back up heating sources using oil, wood, etc.). Such a scenario requires that individuals will utilize their back-up sources during the coldest periods; accordingly the hybrid peak mitigation scenario has the impact of mitigating or reducing the peak requirements associated with the heat pump peak impact.
Load Assumptions – Outcome of 2022 Load Forecast	E1	In addition, NS Power's 2022 Load Forecast is an open regulatory matter currently before the Nova Scotia Utility and Review Board (NSUARB), which offers stakeholders the opportunity to explore key electrification assumptions used in	The 2022 Load Forecast serves as the foundation of the load assumptions for the IRP Evergreen update (I.e. current trends). Like all long-term planning studies, NS Power has proposed alternative plausible futures to assess how different measures

		the 2022 Load Forecast. E1 recommends that the conclusions reached as part of that matter be reflected in the electrification cases used as part of this 2022 Evergreen IRP Update analysis.	could support reductions in peak demand requirements (I.e. the hybrid peak mitigation scenario).
Load Forecasts – EV Charging Profiles and Heat Pump Assumptions	E1	Finally, E1 requests that NS Power share load shape information associated with electric vehicle (EV) charging profiles (both managed and unmanaged) and heat pumps (i.e. electrification load shapes) that form the additional electrification assumptions. The shapes may be important in the types of resource build-out selected by the model.	NS Power can directly discuss with E1 the request for the EV and HP load shape information to better understand the request and assess the potential for information sharing.
Environmental Assumptions	E1	NS Power has proposed a carbon offset cost of \$500 per tonne for use in certain sensitivities, and not as a core scenario assumption. E1 notes that by not including a carbon offset cost as a core assumption, NS Power is effectively assuming a cost of \$0 per tonne. The sensitivity value of \$500 per tonne appears to be on the high-end of the range of carbon offset costs and represents a relatively expensive Direct Air Carbon Capture (DACC) technology. E1 proposes a more moderate carbon offset cost be included in all scenarios, and the higher cost sensitivity (i.e. \$500 per tonne) be included for select scenarios. A moderate cost scenario may be the cost of power generation carbon capture, estimated to be \$50 to \$100 USD per tonne by the IEA in 2019[3]. NS Power should also indicate which scenarios will include the high carbon offset cost sensitivity.	In NS Power's scenarios that do not include carbon offsetting at \$500/tonne, the OBPS carbon tax will continue to be the carbon pricing mechanism modeled (\$170/tonne in 2030, escalating at 2% p.a.). In no scenario is NS Power assuming a cost of \$0/ tonne. Carbon Capture and Storage combined cycle plants are a candidate supply resource that will be made available to the model. NS Power understands that the cost quoted reflects only the variable portion of carbon storage; not the cost of building and operating the asset.
DER	E1	On slide 24 of the Evergreen Draft Assumptions and Modelling Scenarios presentation, NS Power provides an indication that high DER cases will	The intent of assessing the High DER scenario as a sensitivity is to understand what other supply side

		continue to be used in the 2022 Evergreen IRP Update process, as in past cases. E1 notes that the objective function of the IRP is the minimization of ratepayer costs, as opposed to total provincial costs. NS Power should view DER scenarios with the same treatment as electrification – as a potential policy impact that occurs outside of the electricity system, which may affect the total load served. E1 recommends that only in-scope utility costs associated with high DER be included in the analysis. Any participant cost should be excluded from scenario revenue requirement calculations.	resources and strategies are robust as compared to other scenarios. During the 2020 IRP process, E1 requested that NS Power include ratepayer costs in DER scenarios: "With respect to Distributed Resources cases, define the portion of NPV revenue requirement that will be rate-payer funded, and include it within NPV revenue requirements." (E1 Memorandum July 17, 2020, Re: 2020 IRP – June 26 Modeling Results Comments). Similar to the 2020 IRP, NS Power will calculate the NPV Revenue Requirement without the capital and operating costs of the DER resources. However, NS Power continues to believe it is appropriate to attempt to quantify the costs of DER, separately, to provide an understanding of the cost differences when comparing plans and the cost impact of DERs. This is also consistent with the position E1 took during the 2020 IRP process per its comments in its June 17, 2020 memorandum.
Planning Reserve Margin and ELCC	E1	The 2022 Evergreen IRP Update analysis appears to be using Effective Load Carrying Capacity (ELCC) contributions from renewables on an individual basis (e.g. ELCC for wind, ELCC for solar). This approach fails to recognize the diversity benefit described by E3 as part of the pre-IRP development materials.[5] E1 recommends that this diversity benefit be calculated and included, especially given the presence of long-acting storage as a resource option in the 2022	The capacity expansion model is able to select combinations of renewable generators and energy storage when optimal to meet system needs. The respective contribution of each resource to PRM will be reflective of their marginal ELCC as calculated in the 2020 IRP capacity value study (E3). NS Power is considering approaches to incorporating the incremental diversity benefits to ELCC of pairing renewables with storage (see Section 4.3.5 of the 2020 IRP Capacity Value Study).

		Evergreen IRP Update process. E1 further recommends that this diversity benefit be considered for demand response (DR), where it acts in tandem with renewables to support periods of high system load.	While NS Power's IRP capacity expansion model will select battery storage and renewable resources independently, this does not preclude combining these resources into a hybrid project if both resources are selected and key services can be maintained (e.g. locational benefits).
DSM and Demand Response	E1	The table, on slide 28 of the Evergreen Draft Assumptions and Modelling Scenarios presentation, includes the energy and demand savings associated with energy efficiency as part of the characterization of DSM; however, the costs of both energy efficiency and demand response are included in the table. NS Power has indicated that demand response will not be tested as a candidate supply-side resource in the 2022 Evergreen IRP Update and will be 'locked-in' for all scenarios. E1 recommends that care be taken such that all costs and benefits from DSM (i.e. energy efficiency and demand response) are able to be removed for the purposes of avoided cost generation – this will require removal of DR from the load forecast for the purposes of creating the "No-DSM" case. The treatment of DR also remains subject to active discussion as part of the 2022 Load Forecast regulatory proceeding. As for electrification trajectories – E1 recommends that the findings from the 2022 Load Forecast proceeding be reflected in the assumptions used for DR as part of the 2022 Evergreen IRP Update process.	The most current load forecasts, represented in the 2022 Load Forecast filed with the UARB, will be reflected in the Evergreen IRP modeling. Energy efficiency and associated passive demand reduction offers a fundamentally different value proposition than targeted Demand Response programs. Given this, the two programs should not be aggregated together when calculating avoided costs. The economics of Demand Response would require specific analysis, similar to other new supply side resources.

		Additionally, the 2019 DSM Potential Study did not consider the higher levels of electrification described in the 2022 Evergreen IRP Update process as its development predated the integration of large amounts of electrification growth into NS Power's Load Forecast. These electrification loads may provide additional opportunity for energy efficiency and demand response. E1 is providing this context for consideration in the DSM assumptions used in the 2022 Evergreen IRP Update.	
Import Assumptions	E1	The Québec High Voltage Direct Current (HVDC) link appears to have been renamed as the "Atlantic Loop" for the purposes of the 2022 Evergreen IRP Update process. E1 requests that NS Power clarify any differences between the two approaches. E1 notes that the assumed nominal capacity for the link is now 550 MW, as compared to the 1,000 MW contemplated as part of the 2020 IRP assumptions for the Québec HVDC link, with the same costs. E1 requests that NS Power provide a summary of the material changes to assumptions associated with this project, as well as their cause. In addition, E1 has the following questions with respect to import assumptions: - What adjustments are being made (in light of significantly higher fuel costs) to the New England pricing forecasts to represent the Québec import source for the Atlantic Loop?	The Atlantic Loop, as identified in the modeling assumptions and scenarios, reflects a series of transmission expansion projects to enable access to clean imports within the Atlantic region (which includes both the HVDC line from Salisbury, New Brunswick to Quebec and the Reliability tie from Onslow, Nova Scotia to Salisbury, New Brunswick). The 550 MW capacity import limit is generally consistent with the 450MW tested in the 2020 IRP. It is anticipated that the total HVDC line rating would be at least 1000MW, providing opportunity for additional non-firm imports when available. The following include NS Power's responses to E1's follow-up questions: 1. All import pricing forecasts reflect the current state of commodity markets and include estimates of long-term changes to these markets via propriety fundamental analyses.

		- What risks does NS Power view as material risks with respect to future enablement of construction of the Atlantic Loop? - What is the total expected cost for the Atlantic Loop? Are there other anticipated funding partners? - What contract and/or system requirements will be needed to ensure Atlantic Loop imports are Renewable Electricity Standard (RES) compliant, given the imports will be flowing through the New Brunswick system, which currently would not be considered RES compliant? Is there any risk that Atlantic Loop imports would not be considered RES compliant?	Relevant forecast dates have been added to the Final Assumptions. 2. The enablement of the Atlantic Loop is dependent on jurisdictional agreements, the expected stage gate process milestones (engagement, permitting, design and construction) and ensuring affordability. NS Power will continue to monitor and reflect stage gate or other risks as they arise. In addition, future capital filings associated with components of the Atlantic Loop transmission expansion projects will contemplate and assess the detailed risks on a project-by-project basis. 3. The forecast cost of the transmission expansion component of the Atlantic Loop to Nova Scotia Power customers is $1.7B (please see the assumptions slide deck as well for more information on the Atlantic Loop cost projections). 4. The Atlantic Loop project would represent a direct commercial arrangement with a specified counterparty, with an associated transmission path through NB. The attainment of the RES attributes would be specified in a commercial arrangement if one were to be reached.
Imports – Reliability Tie	E1	…all resource scenarios now include a reliability tie with a planned construction date of 2027 – has NS Power had discussions with New Brunswick as part the development of this resource? During the 2020 IRP, E1 observed several risks associated with this proposal, and large infrastructure projects in general. Please explain whether risks have diminished for it to	Execution of the Reliability Tie was included in NS Power's 2020 IRP Action Plan following analysis of that resource in that report. NS Power continues to advance the Reliability Tie project and is progressing the necessary project milestones (e.g. environmental, land access, First Nations and Stakeholder engagement, design) and does not currently foresee risk that would remove the

		be included in each scenario as a common resource option. If, in the view of NS Power, risks remain, E1 recommends including one additional sensitivity to explore a system without this resource being available.	reliability tie as an option. All supply side projects include development risks as do demand side resources (e.g. ability to scale, attainment of energy and demand savings, cost pressures, etc.).
Fuel and Power Pricing	E1	Liquefied natural gas (LNG) continues to pose risks in terms of the availability of supply, as well as material pricing risks. E1 would like to better understand how fuel pricing assumptions have changed relative to the 2020 IRP. E1 requests NS Power provide: - additional quantitative insights on fuel pricing forecasts; - discussion of any perceived risks associated with the forecast; - a percentage change for fuel costs from the 2020 IRP; and - additional details on NS Power's proposed dual-fuel capable resource assumptions (i.e. assumed fuel mix, and pricing assumptions for back-up fuel).	Pricing methodology for natural gas and fuel oil been provided in the draft assumptions. The pricing forecasts are commercial in nature and confidential. For that reason, NS Power is unable to share further details. Dual fuel resources will be modeled as firing on gas inside the IRP model; dual-fuel capability provides reliability of supply that is required for contingencies not typically explored inside a production cost simulation. It also provides a fuel switching alternative in the event that gas prices exceed oil prices, which does not typically occur in long term fuel forecasts but can occur in the short term in periods of volatility.
IRP analysis should consider feasibility risks of major components	SBA	If NSPI's analysis determines that the Atlantic Loop is part of the future preferred plan, it will be a long development timeline involving many parties across provinces and including the federal government. The development complexity holds significant risk, and NSPI's Evergreen IRP analysis should provide insight on what contingencies should be in place if circumstances develop that delay the project or significantly increase its cost.	In response to stakeholder feedback, NS Power is proposing a sensitivity to test an in-service date of 2035 to understand the impacts from a resource, cost and compliance perspective. In addition, NS Power will evaluate the outcomes of the range of modeling scenarios with consideration for the elements raised by SBA (resource mix in the absence of the Atlantic Loop and what information this provides with respect to options, timing and impacts).

		If NSPI is relying on the project for resource adequacy or to meet clean energy requirements in 2030, what are the alternatives if the project is delayed by two years? Or if the project hits a critical issue in 2027 and is cancelled? Will NSPI have sufficient time to develop alternative clean supply plans? A comparison of the "with Atlantic Loop" and "without the Atlantic Loop" scenarios will provide insight on different path options, and NSPI should conduct a critical review of those results to provide insight to the Board and stakeholders of risks and contingency options to ensure that sufficient optionality is retained.	
Options for More Granular EE/DSM Planning	SBA	To better understand how DSM resources can contribute to a low cost, low risk portfolio, NSPI should investigate options to conduct more granular analysis of DSM, including modeling DSM resources as selectable options in the optimization model, rather than assuming a scenario-based DSM buildout. This approach has been adopted by other North American utilities, including Pacificorp and Tennessee Valley Authority (TVA). SBA acknowledges that this change will take significant effort and does not suggest that NSPI needs to implement it in the Evergreen IRP process in 2022. However, SBA recommends that NSPI investigate such a change for future analyses.	NS Power will review the data requirements with E1 to enable DSM as a selectable resource in the capacity expansion model in the future. However, as referenced in the SBA feedback, this is a long term consideration that will not be incorporated into the 2022 evergreen modeling.
Reporting on Reliability Risks	SBA	The 2020 IRP included planning constraints to reflect certain reliability considerations of an increasingly renewable supply portfolio. The	As NS Power communicated in the Action Plan update, wind integration studies are in process. The results of this work will not be ready to inform

		modeling analysis included a system inertia constraint requiring a specified amount of system inertia from online resources. As part of the Action Plan, NSPI acknowledged that additional system stability studies were required to fully assess future reliability as more inverter-based resources are added to the system (Action Plan Item 3d). Given the scope of the Evergreen IRP, NSPI should provide some assessment of whether completed stability studies are sufficient to conclude that the plans produced by the Evergreen IRP analysis will produce a reliable system, or if additional studies are required to make such a conclusion.	modeling constraints for the 2022 IRP evergreen process. As such it is possible that additional measures will be identified as necessary to ensure system reliability at high inverter based generator penetrations. Once complete, this work will influence Action Plan and Roadmap findings for the 2022 IRP Evergreen. NS Power believes that current system strength constraints, including the updated wind integration methodologies, represent the best current knowledge for quantifying system stability considerations in generation planning models for the Nova Scotia system.
Incorporating Potential Short Term Renewable Compliance Options into IRP	SBA	NSPI is faced with the potential for significant financial obligations as a result of the likely growing renewable energy shortfall required for compliance with laws and regulations. These financial obligations could be in the form of penalty payments, purchase of offsets or credits, short-term purchases of renewable energy, or investment in long-lived renewable resources. The IRP should address, perhaps analytically if needed, the impact of this change in 'starting point' for the IRP analyses.	In the short-term, NS Power has limited options to change its generation portfolio by altering the mix of supply and demand side resources. However, NS Power is pursuing options available to it to meet environmental legislation and minimize the costs of compliance. Steps to procure additional clean renewable energy are in process, e.g. the assumed 350MW wind from the Rate Based Procurement (for targeted in-service date in 2024-2025) and other ECEI related projects (e.g. 200MW BESS, NS Power Wind, Coal to Gas Conversion).
Maritime Link and Labrador Island Link Reliability	CA	We previously commented that with respect to the Maritime Link and Labrador Island Link reliability, consistent with the Board's recognition of Mr. Trim's evidence in the Final Assessment suggesting that the reliability of the Maritime Link will be less than 98%, NS Power	NS Power is not in agreement that the ELCC value for the resources delivered via the Maritime Link should change as a result of the short-term/current performance. Since the reliability of these imports is a result of operational factors that are anticipated to be resolved in the short term, the

		should re-evaluate the ELCC of resources delivered via the Maritime Link. The reliability of the Labrador Island Link should also be re-evaluated given continuing issues with the operating deliveries. In response, NS Power stated that it would retain the ELCC value from the 2020 IRP as that value is "reflective of long-term assumptions." While we agree that the ELCC value should be reflective of long-term assumptions, we believe that the Board shares our view that Mr. Trim's evidence established that the long-term reliability of the Maritime Link should be considered to be less than 98%. This evidence was not available for the 2020 IRP. NS Power's response on this point disregards the Board's weighing of the evidence. NS Power should update the ELCC for this resource.	98% ELCC value is appropriate as it is reflective of the long-term reliability assumptions for the resource.
Reliability Tie Considerations	CA	In our previous comments, we recommended that the base case for the IRP include significant schedule contingency for the Reliability Tie construction. NS Power's response indicates that it "will consider whether sensitivities on an alternative assumed timeline would add value to the modeling exercise." Given the issues that emerged in working with Nalcor to achieve timely delivery of the NS Block, we strongly recommend a scenario case, and not a sensitivity, that considers the risks of working with a utility partner (with regulators from another province, with different priorities) on	The modeling scenarios proposed for the Evergreen IRP work in 2022 intend to provide a focused assessment of significant changes since the 2020 IRP while still allowing for a broad range of outcomes. Since the Reliability Tie will serve as a component of what will be the Atlantic Loop, testing scenarios that have the Atlantic Loop in place and scenarios that do not have the Atlantic Loop in place will provide an understanding of the impacts associated with the absence of the clean imports provided by regional integration in 2030. NS Power is proposing to test an additional sensitivity that considers alternative in-service

		such a critical project. We recommend that the sensitivity should consider a delay to 2031, past the date of the mandatory coal retirement schedule. This scenario should be used to develop a contingency plan in the event that the Reliability Tie is delayed. Elements of the contingency plan should be tested for cost-effectiveness in the base case to determine whether, even without a delay, some of those elements might reduce costs ("no regrets" resources) or impose only minimal net costs (low-cost insurance resources). For example, if NS Power had increased its investment in wind resources in parallel to the Maritime Link development, it could have avoided carbon costs and reduced the cost of power during the delay in delivery of the NS Block. We should learn from that example and determine what investments should be made, or positioned for rapid deployment, as the Reliability Tie is advanced. We strongly suggest that such contingency planning be sufficiently developed to include it in the forthcoming application for the Reliability Tie.	dates for the Atlantic Loop and the Reliability Tie-Line. In this scenario, projects will have earliest in-service dates of 2035 and 2031, respectively. This has been added to the modeling scenario plan in response to comments provided.
Renewable Integration	CA	We recognize that NS Power has made substantial improvements to the renewable integration requirements. We have three further suggestions.	The renewable integration studies underway will assess the applicability of the max instantaneous constraint and how it may need to be modified in future long term planning studies. NS Power cannot

		First, we would like to see further justification of the 70% max instantaneous penetration constraint. Once the reliability tie is built, then the 70% constraint would be binding at all load levels below 1,714 MW until 2031. NS Power should verify the need for curtailments throughout that range and potentially consider a higher constraint once the reliability tie (or domestic integration) is fully online (e.g., 75%). Second, the design of the maximum instantaneous penetration constraint, should be adjusted. The denominator of the maximum instantaneous penetration constraint should be the full online capacity including active non-synchronous generation and full unit capacity of all online synchronous equipment (including non-dispatched capacity). This is sometimes referred to as the "Power Electronic Ratio." For example, in an hour with 1000 MW of load, 800 MW generation from wind and 200 MW generation from synchronous generation, the 80% penetration level would violate a 70% constraint. However, if the thermal output was 200 MW coming from committed, partially dispatched generators with 500 MW of synchronous capacity, the power electronic ratio would be 800/1300 or 61% and the constraint would not be violated. When the model determines that the ratio constraint would be exceeded, it could then optimize between curtailing the renewable generation and	confirm at this time if a change will be required but will provide an update when the results of the studies are complete. NS Power notes that this constraint will not be binding at any specific value. It would only be binding under certain conditions. These conditions are based upon the amount of installed capacity of invertor-based resources, their coincident power output and the load in each hour. This constraint was developed by researching jurisdictions leading renewable integration and/or from other public data sources (e.g. EirGrid, NREL). See System Non-Synchronous Penetration definition from Eirgrid which is conceptually similar to this constraint. There is not sufficient evidence to support the modification of the constraint from the basis of a System Non-Synchronous Penetration metric. This constraint is derived to proxy a system stability constraint in a generation dispatch model, which is applicable in timesteps of cycles, rather than the ramping capability on online synchronous generators in MWs per minute. Finally, as this constraint is eased to 90% by 2031, the materiality may be low given the modeling horizon (2025-2050). NS Power welcomes the opportunity to discuss this further with the CA and its representatives. The learnings from the renewable integration studies may indicate a modification to the hourly dispatch requirements. Once this is understood, corresponding changes to the constraints, if any, will be incorporated into future long-term planning

		increasing the capacity of partially dispatched generation. Third, we are not convinced that the maximum hourly dispatch constraint (slide 49) is necessary in addition to the max instantaneous penetration constraint. This is of concern because our understanding is that the stability study modeling identified issues mainly during low load conditions, but the max hourly dispatch constraint would result in modeled curtailments during even the highest load conditions. We would anticipate that the proposed maximum instantaneous wind/solar constraint would fully address system stability risks at low loads. For example, at 1000 MW of load, this constraint would be equivalent to the proposed max hourly dispatch constraint of 700 MW. If the max hourly dispatch constraint is retained, it should be relaxed during high load periods during which time NS Power is likely to have high levels of synchronous inertia available from operating resources. As an additional note, we have recently reviewed another utility's sequential modeling of hourly and 15-minute load and generation to address energy imbalance issues. We may be able to share insights from that review if that is of interest.	studies. NS Power agrees however that there could be some level of redundancy between the max instantaneous penetration and the max hourly dispatch constraint. As such, NS Power will undertake a sensitivity analysis which removes the Max Instantaneous constraint to determine the impacts to the expansion plan and associated production modeling (e.g. energy balance, wind curtailment, etc.). NS Power has determined that the Max Hourly Dispatch constraint should be retained over the Instantaneous constraint as this constraint's foundation is the PSC Stability study conducted for the 2020 IRP. NS Power would appreciate the opportunity to discuss learnings from sequential modeling initiatives in other jurisdictions.
Load Forecast Considerations	CA	We note that the load forecast anticipates load growth of about 10% over a five-year period in the 2030s, and discussion during the stakeholder	NS Power agrees that an increasing Peak/Average ratio and/or a declining load factor presents cost challenges to the industry. NS Power continues to

		call indicated that the peak/average ratio may increase from 1.6 to 2.1. NS Power should conduct a qualitative review to identify operational, supply chain, or administrative challenges that may arise during such a period. Issues may be identified that are best addressed concurrent with the investments to be made over the next five years, such as in software capabilities, design choices (e.g., capability for expansion), and the like.	investigate how electrification initiatives may impact peak and associated peak management strategies to manage non-beneficial impacts. NS Power's proposed Hybrid Peak load scenario is one example of a potential peak mitigation strategy associated with the electrification of heating. The ultimate results of the evergreen IRP modeling scenarios will help inform the Action Plan items, as reflected in the feedback. NS Power notes that it has successfully met similar periods of load growth historically within Nova Scotia.
DSM Plan	CA	We note that since the DSM settlement plan has been announced, further understandings of the cost and pace of compliance with carbon and renewable policies has raised concerns about NS Power's capacity to comply. Fuel costs have also increased, pushing avoided costs even higher. One path to carbon compliance and cost minimization would be to accelerate DSM investments prior to 2026 by revising the settlement plan. NS Power should consider whether updates to avoided costs would justify a higher level of investment in DSM, which might practically be accomplished beginning in late 2024. We also note that the mid DSM scenario requires an unrealistic ramp rate of DSM resources in 2026. A mid DSM scenario that includes an earlier increase in investment (2024-2025) with a more realistic rate of increase	While NS Power agrees that higher fuel costs, in isolation, would result in increasing avoided cost pressures, other aspects are also changing, including load, the impacts of the rate base procurement and the structure of other candidate resource options. Thus, while it is possible that avoided costs have increased since the 2020 IRP, the magnitude of change is uncertain. Further, it is unclear whether DSM activities might be similarly impacted by current cost pressures and supply side challenges and/or having the capability to ramp up activities within a short time horizon. NS Power will provide an update on avoided costs after the evergreen work is complete. NS Power will be receiving updated information from E1 to implement a smoothed trajectory (or ramp rate) between the Settlement Plan and the forecasted DSM projections beyond 2025. This will

		through 2027 would be more useful to evaluate than the scenario included in the draft assumptions.	be included in the assumptions for the Evergreen IRP work this year.
Hydro	CA	While NS Power may not have the capacity to evaluate every potential long-term planning issue in this study, we wish to raise one risk that NS Power should consider at least qualitatively. Given the experience with the Tusket and Gaspereau projects, NS Power should consider whether there is a risk that other anticipated investments in hydroelectric facilities could be substantially delayed, creating a modest resource shortfall.	The impact of marginal capacity resource deficits as a result of capital delays can be understood from the existing scenarios.
General Clarifications	CA	We request the following topics be clarified. - Source of "travel survey data" used by E3 for EV load shapes. - Basis for 15% reduction in CT (frame and aero) capital costs between 2022 and 2030, as this is a mature technology. - Further discussion of geothermal opportunity in Nova Scotia (or via transmission). District heating was mentioned during the stakeholder call, please explain how this relates to the system modeling. - Justification for 5% reduction in SMR capital costs between 2022 and 2030, as the earliest proposals for deployment are in the late 2020s (which is highly speculative). - Explanation of coal-to-gas cost estimates, including whether these are plant-specific. What class of estimate is represented?	The following are responses to the items for clarification in order: 1. The source of the travel survey data was from the New England data set. This was chosen based on the similar population and climate characteristics to Nova Scotia. 2. There is a typo in the 2030 price of CT Frame's. The correct value, $1183 vs 1103, reflects a ~8% real $ decline over the period (or ~ -1% p.a. CAGR). Note that the costs of mature technologies, like gas turbines will increase on a nominal dollar basis. 3. Geothermal was cited by the Federal ECCC in their Clean Energy Standards (CES) discussion paper as an emerging technology intended to support the path to net zero. As such, NS Power is including this as a resource option with an "availability timing" into the future that enables the development of this emerging

		- Please explain how the 200 MW BESS for 2024 would have no variable O&M, considering that battery cycling is usually associated with degradation that could require adding additional storage capacity periodically to maintain performance. - Long duration storage: - Please discuss whether an earlier build date (e.g., 2028) should be evaluated in relation to the coal retirement deadline. - Please explain the capital cost trajectory given the build date projection. - Please explain how long duration storage would operate without O&M costs. - Consider whether there should be an assumption that any long duration storage project would operate at lower-than-design performance for the first year or two as operational experience is earned. - Please explain why the Mersey capital forecast does not include a major refurbishment.	technology in Nova Scotia. If geothermal is selected as a resource in the evergreen IRP resource plans, further work will be undertaken to verify assumptions. 4. The justification for the SMR capital costs reflect currently available public information. A <-1% CARG real dollar cost decline, and a cost increase on a nominal dollar basis, was determined to be reasonable given the degree of interest, number of proposed projects and R&D in the technology. 5. Coal to gas estimates are plant specific estimates. The cost estimate includes plant specific investments (piping and boiler conversion) and estimated natural gas pipeline costs. The combined cost estimate reflects a range of component cost estimates from conceptual to design. 6. To NS Power's knowledge, there is limited commercially ready long-duration storage technologies available, with the exception of pumped hydro storage. NS Power does consider pumped hydro storage to be a viable option in Nova Scotia, however, its development lead time is long. Thus, NS Power feels 2030 is a reasonable estimate of when a commercially available 'new' technology (e.g. X element BESS, CAES, other) could become available, or the time to develop a conventional pumped storage facility. However, NS Power agrees that testing a possible earlier date (earliest build date) may provide valuable

			insights on the economic viability of this emerging resource, particularly as a potential capacity replacement for coal. Thus, NS Power has modified the earliest build date to 2028. . Like that of other emerging resources, should this technology be consistently chosen in capacity expansion modeling, it would indicate the need for additional research to confirm or build more confidence in the input assumptions (including costs, capability and technological readiness). 7. NS Power has added a cost estimate for O&M in the updated assumptions. 8. For any resource that is made available in the PLEXOS model, the assumption is that the resource is fully operational at the time of availability. 9. The Mersey project team is currently assessing the path forward for capital investments for the Mersey system. Until this is finalized, the assumptions for Mersey will not include a major refurbishment. As with all existing resources, as new information is understood, NS Power will assess as needed.