NS Power Responses to Stakeholder Comments: Updated evergreen IRP Assumptions and Draft Modeling Results

Stakeholder	Comment	NS Power Response
Bates White	As a high-level point, something that sometimes gets lost in IRP development and reporting is a discussion of what actions (and when) will be informed by the analysis results, and what are the most important uncertain factors that will determine what a cost-effective system of the future will look like. While we understand that the deck is explicitly an update to assumptions, we think that these are things that should be stated and repeated for everyone's benefit whenever NSPI is reporting on the IRP process. Relatedly, it could benefit everyone to answer the question: is the IRP primarily driven by these factors (such as the coal-phase out by 2030), and what really is left to decide based on the modeling? Or is the IRP coming to grips with what needs to be done without much choice? Given the pace of change on battery storage as an example, we think the emphasis should be on maintaining flexibility to take advantage of likely rapid technological changes.	The evergreen IRP process will ultimately provide an update on the IRP Action Plan items. The outcome of the current modeling, and any updates to the Action Plan items as a result, will be presented to stakeholders. As part of a parallel process, NS Power has provided an update on the current Action Plan Items and will be reviewing with stakeholders.
Bates White	Slide 6 – The load forecast has changed in shape substantially, and we note your acknowledgment that post-2030 annual load growth is forecasted to be as high as 10%. 10% growth in the 1966-1975 period reflected circumstances different from today, and rapid growth in that period across North America was notoriously used	The load and peak demand forecast are based on the forecasted pace of electrification, as a result of both economic drivers and legislated initiatives (i.e. electric vehicle adoption targets). This forecast is supported by the electrification strategy work undertaken by NS Power and E3 (please see the 2022 Load Forecast Report and the

	to justify big investments in large central station plants including nuclear that created a range of problems.	February 2023 IRP Action Plan Update re: NS Power Electrification strategy (PowerPoint Presentation (nspower.ca)). NS Power notes that new unit sizes in the evergreen IRP are limited to approximately 150MW or less, due to the size of our system and our limited transmission interconnections to other jurisdictions. These are generally added gradually over time which to some degree mitigates the risk noted.
Bates White	We noted that capital cost estimates for generators (slide 17) are down in most cases from the 2020 IRP data, except for peakers, SMRs, and coal-to-gas conversions. The updated peaker and C2G conversion costs can have an impact on results, as those types of resources were selected in some 2020 IRP scenarios.	NS Power agrees that the higher peaker costs may adjust the low-cost resource mix relative to the 2020 IRP. NS Power has also added HFO conversion options as a new capacity resource type which can provide similar capacity services to peaking units. Both of these are anticipated to affect the optimized capacity resource mix in the evergreen IRP results. From a capacity expansion modeling perspective, if the relative difference in costs between candidate resources remains consistent, the resource portfolio that generates the lowest cost plan will not change.
Bates White	The DER adoption assumptions (slide 25) may be a little aggressive, though we understand this is only for a sensitivity run. Does Nova Scotia have 1.5 GW of distributed rooftop solar potential?	This is a bookend scenario to assess aggressive DER penetrations and is consistent with the scenario modeled in the 2020 IRP (see 2020 IRP Final Report Section 4.1.4).
Bates White	Slide 32 contains the power import assumptions which includes the new addition of the Atlantic Loop scenarios, which allow for 550 MW of firm capacity and firm energy imports. The 2020 IRP did not look at this option. We noted too that the "other regional import via new transmission" option was reduced to "up to 120 MW" from 150 MW in 2020. This creates a large delta	The size of the Atlantic Loop as modeled in the evergreen IRP is in keeping with the Regional Integration scenario from the 2020 IRP, which allowed for 450MW of firm capacity imports. Where the Atlantic Loop represents a new HVDC line, there is limited cost savings potential from reducing the capacity of the line as many costs are largely fixed regardless of line capacity (i.e. majority of

	between the megaproject (Atlantic Loop) and more modest transmission expansion projects. We think it would be beneficial to model transmission expansion in the 150 MW – 250 MW range to get a better sense of the incremental impact of the Atlantic Loop.	right of way, construction, and tower/conductor costs would not reduce significantly if the capacity of the line were lower). In the evergreen IRP, the capacity expansion model is able to optimize capacity purchases from the Atlantic Loop in the range of 50 to 550MW. This provides insight into the tradeoff between firm capacity purchases and domestic capacity resources (i.e. new gas units or fuel conversions). NS Power agrees that separating the capacity and energy contributions of the Atlantic Loop could be insightful and will consider approaches to examine this.
Bates White	Slide 34 contains the cost assumptions for the Atlantic Loop. The capital cost estimate is probably stale—has NSPI made any effort to update it? Moreover, how does NSPI arrive at the energy and capacity costs? We see the explanation ("based on updated NE market forecast, adjusted to represent Quebec import source"), but we wonder if this is optimistic. We'd view NSPI's portion of the capital cost and any energy/capacity offtaker agreements to be related—does NSPI have any indicative offers from HQ about what these costs would look like? We'd also be interested to see the actual energy and capacity prices being assumed, since they don't appear to be in the slides. Lastly, we wonder if some sensitivity cases regarding Atlantic Loop costs (capital costs, energy and capacity payments) would be warranted given the megaproject nature of the Atlantic Loop and the numerous counterparties and regulatory bodies involved in its development and approval.	The capital costs identified for the Atlantic Loop reflect the best available information of the project cost to Nova Scotia customers at this time. NS Power is using a third-party, fundamental long-term forecast of energy and capacity pricing in the NEPOOL market to proxy HQ energy and capacity pricing. These forecasts are adjusted for foreign exchange and transportation costs to reflect a landed NS price. An adder has been applied to these monthly estimates, across the entire horizon, to reflect a market premium for clean energy. NS Power has provided import cost curves that reflect forecasted seasonal average Atlantic Loop energy pricing (please refer to the following location on the NS Power IRP website for the data and charts: Document Library → 2022 Evergreen IRP). Capacity costs and NS Power's portion of capital costs represent fixed costs in the evergreen IRP model. Thus, as these estimates become better defined over time,

		fixed costs can be updated without invalidating the modeling results or comparison between scenarios. Based on stakeholder feedback, NS Power also has included CE1-E1-R1-AAT (Atlantic Loop Adjusted Timing) as this sensitivity requires a PLEXOS evaluation to understand the full cost impact, unlike an adjustment to fixed costs which can be completed outside the model.
Bates White	Another assumption that is a little surprising is the new natural gas-fired resource assumptions on slide 38. They are assuming no long-term firm gas commitments or infrastructure builds, and instead will model just peaking gas units that are also required to be dual fuel units (which raises their costs). What is the justification for this limitation? It would be beneficial to explain to the reader how this limits the number of gas-fired options that can be selected by the model and why the more expensive options have been removed from consideration—especially in light of the faster coal phase-out.	The 2020 IRP evaluated gas units that could be supplied through either i) gas supply characterized by high volatility and peak season supply constraints or ii) gas supply with less volatile pricing and firm supply but with corresponding long-term fixed costs associated with pipeline expansion to our region. The former option was selected in all 2020 IRP scenarios which faced more stringent emissions constraints (i.e. the 3.X scenarios). The 2022 Evergreen IRP has much more aggressive carbon constraints (i.e. carbon price to $170/tonne) and more uncertainty on potential additional restrictions as a result of the Federal Government's proposed Clean Electricity Regulation. As such, assessing a gas supply option that requires baseload utilization and the requirement for infrastructure upgrades outside of Nova Scotia adds complexity to the model, with a very low likelihood of economic selection. Notwithstanding the model structure, this modeling decision does not preclude NS Power from evaluating new opportunities for natural gas supply and transportation in the future.

		For clarity, in the evergreen IRP there is no restriction on the type of units available (including combined cycle units). Due to the single pipeline source of gas into the Maritimes, NS Power will require all new gas-fired units to maintain dual-fuel capability to avoid a large potential single contingency.
Bates White	The presentation of the sustaining capital data makes it difficult to compare to the 2020 assumptions, since the data is now broken down by "fixed" portions (in $) and "variable" portions (in $/MWh). (Slides 42-48). We'd suggest NSPI update the assumptions to explain and characterize any changes to the overall sustaining capital cost assumptions.	Please refer to the February 2023 IRP Action Plan Update (pg. 40 – 41, pg. 45) for an assessment of the changes to the sustaining capital since the 2020 IRP for thermal units, CT units and hydro systems. For the hydro systems and the CT and thermal units, the sustaining capital is forecasted to be lower than the 2020 IRP assumptions.
CanREA	In CanREA's 2050 Vision, we speak specifically about the importance of rethinking electricity infrastructure investments in order to minimize the cost of new transmission and distribution infrastructure. This transmission will be needed to expand electricity production, and we can achieve this expansion by using existing infrastructure more efficiently, and deploying non-wires alternatives into the grid (e.g., energy storage technologies and distributed energy resources). We are pleased to see that NS Power has considered stakeholder input regarding the 2020 IRP integration methodology and has refined this constraint for the 2022 Evergreen IRP to include more wind and solar capacity additions without the additional requirement of specific integration assets. However, CanREA would like to emphasize that energy storage will be a necessary addition to the grid during the next decade as a stabilization measure, especially for use during peak periods.	NS Power agrees that energy storage can be a cost-effective enabler of the integration of variable renewable energy resources on the system. As communicated in the evergreen IRP assumptions and demonstrated by the draft modeling results, BESS resources enable additional integration of variable renewable energy at the hourly dispatch level in addition to providing firm capacity and energy arbitrage services. NS Power agrees that regional collaboration is a key enabler of electricity decarbonization and is pursuing this via its IRP Action Plan, including the Reliability Tie and Atlantic Loop initiatives.

	Even if all scenarios lead to an incremental amount of wind, solar, and energy storage in Nova Scotia's energy mix, CanREA would like to reiterate that increased regional collaboration and co-operation in electricity infrastructure investments would optimize the use of electricity infrastructure and have significant impacts as Nova Scotia strives to achieve their net-zero commitment.	
CanREA	CanREA would also like to request that the IRP Team take into consideration current economic circumstances, as all industries, including the renewables industry, are facing rising material costs, freight costs, and logistical bottlenecks. For example, costs have risen significantly in 2021 and 2022 for critical wind turbine inputs including steel, aluminum, copper, fiber glass, and resins. This ultimately results in increased costs for towers, blades, foundations, and nearly all other wind turbine components. We do not think the current economic landscape was sufficiently considered in the January 2023 IRP update, and we look forward to seeing the economic landscape better reflected in the final presentation of the IRP plan.	NS Power agrees that recent inflationary pressures may have affected resource costs, including those for renewables and storage. The Draft Results indicate significant near-term additions of these resources, displacing energy from existing facilities. In response and to test the robustness of these resource additions to higher resource prices, NS Power will add a 'High Renewables and Storage" capital cost scenario to assess how meaningfully higher assumed capital costs impact expansion decisions for these types of resources.
CanREA	Every province should consider price within their own provincial context, as well as within national, and global contexts. For example, we encourage Nova Scotia Power to consider their price according to the Nova Scotia context as the recent procurement in Nova Scotia had a 100 MW limited nameplate capacity and subsidies that should not have been included in a price analysis. Furthermore, the average energy rate of the Rate Based Procurement portfolio that may have included a subsidies fund from the Smart Renewables and	The Rate Base Procurement resources are fixed in the model based on the selected projects. All other cost metrics for new wind are based on publicly available sources for costs and have been adjusted to include the anticipated Federal Investment Tax Credit. The cost assumptions for new wind resources are not directly based on the successful bids from the Rate Base Procurement portfolio.

	Electrification Pathways Program was $53.17 per megawatt hour. Therefore, we think the IRP team should include a column that reflects the energy rate, allowing for unique provincial context consideration, in the IRP plan. With this in mind, we encourage the IRP Team to update their 2020 cost energy analysis, per technologies, by taking into account the 2022 economic landscape and considering Nova Scotia's unique context in the upcoming Integrated Resource Plan.	See response above regarding a High Renewables and Storage Cost scenario to enable further robustness testing of new resource additions.
Consumer Advocate	The draft results are interesting, but because the updated assumptions are so significant, they do not merit substantial discussion. In response to our informal request, Resource Insight understands that NS Power will provide an 11-year NPVRR metric (2025-2035 inclusive) to provide additional context when comparing model scenarios. We appreciate the addition of this metric. On reflection, we recommend also including an 11-year NPV capital investment metric. This will provide additional context when comparing portfolios with similar long-term NPVRR and emissions but where one emphasizes greater near-term capital investment and thus less flexibility to make adjustments should federal or provincial policy shift again in the near term. We also recommend that NS Power give greater attention to consistency in comparative language among the scenarios. For example, in the observations regarding CE1-E1-R1-MMDSM, the $0.4B difference relative to CE1-E1-R1 is described as "higher" when it is only 1.5% higher. In contrast, when comparing the same	NS Power will include the requested 11 Year NPVRR for the final modeling results. NS Power will explore whether an informative 11-year NPV capital investment metric can be calculated from the current model structure. NS Power appreciates the CA's feedback on result descriptions, it will be incorporated when providing the results of the final modeling results.

	scenarios on total emissions (17.8 vs 16.9), the MMDSM scenario's relatively larger 5% reduction in total emissions is characterized as a "comparable emissions profile."	
Consumer Advocate	Overall, NS Power's updated assumptions are consistent with the approach taken in prior modeling activities with continued incremental improvement responding to our and other stakeholders' feedback as well as new circumstances. We have two recommendations and several comments. First, Resource Insight recommends that NS Power work with Efficiency Nova Scotia to adjust the MMDSM scenario to begin increasing above the current approved DSM plan in 2025, rather than waiting for 2026. We view the draft results for the MMDSM scenario as promising. Given the challenge of meeting the 2030 coal retirement deadline, accelerating the increase in DSM impacts by one year could have a significant cumulative impact by 2030. We understand that it is NS Power's view that the IRP is not the venue in which it would prefer to re-open the settlement agreement regarding the DSM plan. However, circumstances have changed even since the Board approved that plan and we view it as in customers' interests to understand all the options that are practically available. Following a lengthier process in which the issue is first raised in the DSMAG and eventually referred to the IRP process for modeling introduces delay, which makes the process for revising the approved DSM plan less and less practical. We would hope that NS Power would wish to	The MMDSM scenario was developed by E1 as a response to enabling a reasonable transition from the 2023-25 settlement plan to the forecast beyond 2030 as an outcome of discussions following the release of the evergreen IRP modeling scenarios and assumptions. NS Power notes that the cumulative energy and demand reductions of the MMDSM scenario are actually higher than the original Mid DSM scenario despite a slower ramp in the spending rate, suggesting that the MMDSM scenario already incorporates accelerated efficiency measures based on update programming assumptions by E1.

	evaluate technically feasible resource options such as advancing the MMDSM ramp-up to begin in 2025 rather than 2026 in this process, and then, if merited, consider whether it is practical and prudent to make such a change within the DSMAG and planning processes.	
Consumer Advocate	Second, we appreciate NS Power's explanation as to why the impact of the continuing deferral of the decision to invest in (or decommission) Mersey is not of material importance to meeting the planning reserve margin. Nonetheless, with the continuing deferral of a decision on Mersey, the reliability of the system from both storage (civil works) and generation perspectives decreases. Should a significant failure occur, the question of whether expensive repairs are merited may not be easily resolved outside a full capital application for the Mersey project. Should such lengthy delays occur, this could significantly affect the annual generation provided by the Mersey project. The IRP modeling should account for this elevated risk of an extended outage at Mersey because it may introduce a material shift in the optimal resource investment portfolio.	NS Power agrees with the CA's comment that there is a benefit to assessing the elevated outage potential for the Mersey system. Based on this, the modeling representation for the Mersey system has been updated by imposing a 15% DAFOR, which will simulate randomized system outages, impacting energy production of the hydro system and resulting system production costs. NS Power has also reduced the ELCC of the Mersey system from 95% to 85% for the final modeling results.
Consumer Advocate	In addition to these two recommendations, we have observations about several updates to the assumptions. Regarding the reliability tie, it is our understanding that the earliest possible date for its completion is now 2027, rather than 2025, due to NS Power's decision to suspend investment commitments as a result of what it has described as constraints on its ability to obtain capital as a result of Bill 212. Otherwise, it is our understanding	Reliability Tie: The currently projected 2027 earliest in-service date proposed for the Reliability Tie is based on the draft project plans developed in conjunction with NB Power, and reflects anticipated timing for project approvals, procurement, construction, and commissioning. Hydrogen:

	that there are no obstacles to methodical development of that project. Resource Insight agrees with prior findings from NS Power's IRP work that the reliability tie is an essential foundational requirement for progress on many of the elements of the province's decarbonization. We urge NS Power to advance this project as rapidly as possible consistent with cost management and other best practices. Regarding the hydrogen emerging technologies evaluation, we agree that this is an important part of the IRP evaluation. Our understanding is that the technical path to building generation fueled by hydrogen (or ammonia) is relatively well understood, albeit with some uncertainty as to when it can be delivered. What is less certain is the market for procuring hydrogen. One issue is the necessity to ensure that domestic production of hydrogen is powered by renewable energy. We view the use of biomass to power electrolysis as inefficient and potentially unreasonable. It does not make sense to burn fuel to generate electricity to make fuel that will be burned again to generate electricity. We encourage NS Power to work towards a modeling solution that presents electrolysis as powered by wind and solar, potentially augmented by hydro. Another issue related to hydrogen is the need to plan in coordination with other potential domestic users of hydrogen fuels, notably in industry and transportation (e.g., marine shipping).	NS Power notes that while biomass is considered RES compliant in Nova Scotia, it is not currently considered "green hydrogen" compliant by the EU, which NS Power understands to be the main target for export-focused hydrogen developers in the region and ultimately the source of domestic hydrogen. It is also relevant to note that NS Power is not offering new biomass resources in the evergreen IRP model. Although biomass is considered RES compliant in Nova Scotia and therefore would serve the hydrogen load in the IRP model, it's contribution to the overall load requirement is small in comparison to other resources (often ~300GWh/year). The renewable requirements to meet the hydrogen load in the DH scenarios can be assessed via post-processing. NS Power notes and appreciates the CA's comment re: economy-wide utilization of the domestic hydrogen resource. It is important to note that with the assumed hydrogen prices, NS Power does not anticipate hydrogen enabled CTs to be used as anything other than peaking facilities, which will reduce the fuel demand requirements. Renewable Integration: NS Power agrees that the large power electronics-based load expansions will require study via Electromagnetic Transient (EMT) models, in order to ensure that the reliability of the power system is not adversely affected. NS Power appreciates the feedback regarding refinement of the integration constraints and the recommendation to join the Energy Systems Integration Group. NS Power's System Planning Team closely follows the work of ESIG and similar initiatives.

	The implications of large inverter-based load on the NS Power system need to be understood and planned in conjunction with generation and transmission resources. Finally, we wish to express our appreciation for NS Power's continued efforts to update its renewable integration planning methods. As NS Power well understands, the scale of wind resource deployment on its system may be relatively unique in the western world for a near island electric grid. Along with the integration of hydrogen production challenges, this work will challenge NS Power to be among the leading utilities in the world. One possible opportunity for collaboration might be for NS Power's planners and engineers to participate in the Energy Systems Integration Group, a non-profit that includes utility and other experts dealing with these issues in Europe, North America and Australia, among other countries.	
E1	After reviewing the draft results and updated assumptions released by NS Power in January 2023, E1 recommends a stakeholder workshop to further discuss and gain clarity prior to completing and issuing modelling results on March 30th. E1 believes that such a workshop would be valuable to gain a better understanding of the materials and to support fulsome stakeholder engagement since the outcomes of the IRP impact future DSM Planning assumptions.	NS Power allocated time during the IRP Action Plan Update stakeholder engagement session on March 21 to answer questions related to the draft modeling results.
E1	Relative to the 2020 IRP, the 2022/2023 IRP Evergreen Update reflects a number of decarbonization requirements, higher fuel prices, continued uncertainty around the Atlantic Loop and firm imports, and, in some cases, increased reliance on distributed energy resources (DER). These factors suggest that additional DSM, beyond the base DSM level, may be desirable. DSM	Both the modified mid and Base+ DSM will be tested as sensitivities. NS Power notes that Base+ represents an increase in annual cost of approximately \$20M-\$30M relative to Base (~33%-50%) and so NS Power does not believe it is appropriate to change the default DSM profile from the one selected in the 2020 IRP without further analysis.

presents a low-risk, "no-regrets" resource that will bring benefits to customers and the utility in all scenarios. It is less prone to cost or timeline overruns that are commonly seen with other major resource investments that are being contemplated such as the Atlantic Loop, nuclear, and hydrogen. In a time where there is great uncertainty about what the electricity system will look like in ten or twenty years, everything points to the need for more DSM.

While the updated DSM cases in the scenarios as of January 13th, 2023, are recognized and appreciated, E1 recommends that Base+ be used as the default DSM case for all scenarios going forward, with Modified Mid being used as a secondary case – as outlined in Table 1 below.

Scenario	Primary DSM	DSM Sensitivities
CE1-E1-R1 CE1-E1-R1-*[1]	Base+	Modified Mid
CE1-E1-R2 CE1-E1-R2-*	Base+	Modified Mid
CE1-E2-R2 CE1-E1-R2-*	Base+	Modified Mid
CE2-E1-R1	Base+	Modified Mid
CE2-E1-R2 CE2-E1-R2-*	Base+	Modified Mid

The Modified Mid DSM scenario can be considered a replacement for the Mid DSM scenario from the 2019 Potential Study. Given historical and approved DSM levels through to 2025, the Mid scenario now contains an unrealistic ramp up of DSM activities from 2025 to 2026; Modified Mid was designed to account for a more realistic ramp-up of activities from approved DSM to Mid DSM levels.

NS Power notes that in the Draft Results, the MMDSM case had a higher NPVRR than the Base scenario. Base+ is in between these two profiles and so will also be tested as a sensitivity to understand its behavior.

E1	In scenario CE1-E1-R2-HDER NS Power models the Net Present Value Revenue Requirement (NPVRR) for the utility system costs as well as the customer capital costs for solar. On slide 11 of the evergreen update, NS Power stated, *"NPV Difference - ~$1.8B higher NPV as compared to CE1-E1-R1 (with end effects) including [the] cost of DER resources."* This NPV comparison appears to include both the utility NPVRR and the customer capital costs for solar. E1's position on this has been consistent throughout the 2020 IRP and IRP Evergreen update. E1's position is that: - All utility costs should be included in the utility NPVRR, including any required ratepayer-funded programs to support adoption; and - Customer costs may be presented for information purposes but must be excluded from utility NPVRR (consistent with all other demand-side options such as electrification and DSM). In this case, it appears that the DER resources referenced are the customer capital costs. E1 requests that NS Power confirm the modeled customer capital costs will be excluded from the selection of a preferred resource plan. E1 further requests that the cost treatment of all demand side resources be consistent. This includes energy efficiency, demand response, solar, batteries and electrification. All utility costs, including the cost of any required rate-payer programs must be included. Customer costs may be quantified but must not be included in the utility revenue requirement.	NS Power has provided separate NPVRR and the solar capital cost values in the draft modeling results summary, distinguishing the NPVRR value from the DER Solar capital cost. Potential mechanisms associated with incenting the significant volume of customer adoption of rooftop solar in the HDER scenario have not been incorporated into the model. The HDER scenario represents one sensitivity in the overall Planning Study. NS Power does not have the data requested. NS Power notes E1's recommended review of the solar CAPEX cost. The current CAPEX assumptions are based on $3/watt (2022$). The forecasted cost decline trajectory is used to adjust the base estimate for subsequent additions and is based on the NREL ATB 2021 Utility PV (Index | Electricity | 2021 | ATB | NREL).

	Scenario CE1-E1-R2-HDER assumes significant adoption of behind the meter solar. Has NS Power considered what mechanisms would be required to achieve these higher levels of solar adoption? If yes, what level of electricity ratepayer-funded incentives has NS Power included to bridge the gap between current adoption levels and the proposed solar capacity modeled in CE1-E1-R2-HDER? If no ratepayer-funded incentives were included, how does NS Power expect that gap to be closed? In CE1-E1-R2-HDER NS Power has assumed the customer CAPEX cost of solar is $3/watt. In E1's experience, residential solar projects are approaching $2.5/watt. E1 recommends that if solar customer costs continue to be quantified, the assumption of $3/Watt be reviewed. Finally, E1 requests that NS Power provide a copy of the National Renewable Laboratory's (NREL) forecasted cost decline trajectory used to adjust the solar CAPEX base estimate.	
E1	NS Power states that "PLEXOS load modeling will be improved relative to the 2020 IRP by incorporating hourly shapes for incremental EV and heat pump load to capture impacts on the base load shape." E1 submits the following questions to NS Power in relation to their Electrification Strategy: - Is electrification strategy work on-going? If so, when will it be completed? - Is there ratepayer funding included in the IRP assumptions for electrification? If not, how does NS Power expect adoption at the levels included?	Yes, the electrification strategy work is ongoing. Please refer to the February 2023 IRP Action Plan Update for more details (link). The electrification strategy will be made available to stakeholders when completed. Potential customer electrification costs are not included in the evergreen IRP. The electrification assumptions included in the evergreen IRP work are an adoption of the peak and generation forecasts reflective of the building heating (scenarios described on slide 7 of the updated assumptions (IRP Evergreen - Updated Assumptions (nspower.ca)) and the EV load shapes, which were developed by E3. While ratepayer funding was not

	- Will the electrification strategy be made available in its entirety to stakeholders including data regarding load shapes?	included in the model, the load shapes were developed based on policy requirements and industry data. For example, the load shapes were developed based on stock rollover predictions to achieve economy wide net zero targets by 2050 for the building heating scenarios and EV load shapes. In addition, E3 based the EV shapes on a bottom-up forecast of transportation load based on simulations of EV driving and charging behavior, using travel survey data. The monthly forecasted generation and peaks for each load type based on the E3 work are used to create the forecasted hourly loads. As a result, the hourly EV and building heating loads modeled in PLEXOS are reflective of adoption trends influenced by both the policy requirements and industry data.
E1	In the 2022 Load Forecast, E1 made the following recommendation: *"That the heat pump modelling in the load forecast be updated to reflect the current adoption trends of cold climate heat pumps with a minimum COP of 1.75 at -15C, and the removal of any 'lock-out' temperature that is not aligned with the COP performance of modelled heat pumps."* In its Rebuttal Evidence, NS Power stated: *"The scenario modeled by E3 assumed a COP of 2.3 at -15 degrees Celsius for new heat pumps installed over the forecast period. Additional analysis, including removal of the lock-out temperature, is incorporated into NS Power's ongoing Electrification Strategy work under the IRP Action Plan."* Has the additional heat pump analysis referenced in NS Power's Rebuttal Evidence been completed? If yes,	The current electrification load assumptions (based on the 2022 load forecast) assume a coefficient of performance based on declining outdoor temperatures. The load forecast assumes a COP of 2.3 at -15 degrees Celsius for heat pumps. The electrification load assumptions will be adjusted in the future to reflect updated heat pump load impact curves as part of the electrification study work supported by E3 when it is finalized.

	please provide the results of this analysis with all workpapers and materials. Do the current electrification load assumptions used in the IRP include any heat pump lock-out temperature? If yes: - What are the specific heat pump temperature lock-out assumption(s)? - When will the electrification load assumptions be adjusted to remove this lock-out temperature?	
E1	On July 29th, 2022, in response to E1's comments about avoided costs, NS Power stated: *"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."* E1 will require updated avoided costs (energy, capacity, carbon, transmission, and distribution) for development of its 2026-2030 DSM Plan by the end of 2023. E1 expects that a fulsome and transparent stakeholder engagement approach will be undertaken for the development of all updated avoided costs throughout the second half of 2023. E1 requests NS Power outline the schedule of activities and stakeholder engagement for updating all avoided costs (energy, capacity, carbon, transmission, and distribution) to allow for finalized avoided costs available for E1 by December 31, 2023.	In its June 10, 2022 letter to the NSUARB regarding E1's 2023 – 2025 DSM Plan Application, NS Power provided the following: "The avoided costs methodology used in the 2023-2025 DSM Plan was recently developed following a thorough and lengthy stakeholder consultation process. For the purposes of DSM program planning, avoided cost data will not be required again until 2025, when it will be required for the preparation of the 2026-2028 DSM Resource Plan. NS Power confirms that it will work with E1 and the DMSAG in advance of the 2026-2028 DSM Resource Plan to discuss any updates to avoided costs. This timing will allow for the alignment of updated costs with changes that may arise in the long-term planning environment. NS Power has committed to ongoing evergreening of the IRP from time to time, so there will be more current updated scenarios from which to base updated avoided costs, if appropriate/necessary, in advance of the 2026-2028 DSM Plan development."

		The NSUARB subsequently provided the following regarding avoided cost data in its September 7, 2022 Decision regarding E1's 2023-2025 DSM Plan: "[63] In its rebuttal evidence, NS Power responded to the CA's suggestion by noting that avoided cost data will not be required again until 2025, when it will be needed to prepare the 2026-2028 DSM Resource Plan. In the meantime, ongoing "evergreening" of the IRP will result in more current updated scenarios from which to base updated avoided costs, if necessary, prior to the 2026-2028 DSM Plan development. NS Power confirmed in its closing submission that it will work with E1 and the DSM Advisory Group to discuss potential updates to the avoided costs in advance of the 2026-2028 DSM Resource Plan. [64] The Board understands that recently legislated climate change reduction goals are not addressed in IRP Reference Plan 2.0C, nor are they fully addressed in Reference Plan 3.1 C. The Board agrees that these factors need to be incorporated in updated avoided costs; however, there is no immediate urgency and directs that this issue be tasked to the DSMAG to be resolved in time for use during preparation of the 2026-2028 DSM Plan." NS Power's position re: provision of avoided costs has not changed. NS Power will be able to provide updated avoided costs of capacity and energy following the completion of the evergreen IRP.
E1	Given that both energy efficiency and demand response can provide peak demand reduction, E1 believes it is reasonable to apply the same avoided costs for this use	Please refer to the previous response. This is outside the scope of the evergreen IRP however, NS Power will work with the DSMAG on the methodology.

	case to both. E1 agrees with NS Power that demand response can provide additional use cases, and the utility benefits of these use cases should be accounted for. This could be accomplished through either: - Separate avoided costs for use cases such as fast frequency response and operating reserve to be applied to demand response capacity, or - A combined demand response avoided cost, which values all demand response use cases including peak demand reductions. E1 is open to either of these solutions; however, the previous treatment of only partial benefits/costs of demand response in the DSM avoided costs is not an appropriate option (as raised by Synapse). E1 requests that NS Power propose an appropriate methodology for valuing the avoided costs of demand response, which can be implemented by the end of 2023. E1 requests NS Power outline the schedule of activities and stakeholder engagement for the proposed methodology to allow for finalized avoided costs of demand response to be available for E1 by December 31, 2023.	
E1	E1 continues to have concerns that the demand response assumptions being used in the IRP are not based on the best available information. In its 2023-2025 DSM Plan, E1 provided a 10-year roadmap developed by Guidehouse of demand response capacity it could deliver, as well as time varying pricing (TVP) projections based on data available during development. Guidehouse's 10-year demand response model from E1's 2023-2025 DSM Plan is the best available forecast of demand response. E1 recommends that it is incorporated into IRP assumptions. If there is interest in	The achievable potential of the current Demand Response projects, including the value of the Critical Peak Pricing (CPP) project, is included in the load forecast. In the evergreen IRP DR programs are no longer modeled as a supply side resource. The total impact of the E1 DSM settlement plan is included in the PLEXOS model, which includes the cost of DR. As part of the NSPI 2022 Load Forecast regulatory process, E1 posed a similar question re: EV managed

	exploring additional levels of demand response, E1 recommends this be assessed through a high demand response sensitivity (this could utilize previous Guidehouse work from the 2019 Potential Study or updated analyses). Questions: - How have NS Power's TVP rates been incorporated into the load forecast? - Please confirm that demand response costs included in E1's approved 2023-2025 DSM Plan have been removed from the DSM cost streams used for 2023-2025. - How is NS Power treating the duplication of electric vehicle managed charging assumptions currently contained within both electrification load assumptions and demand response assumptions?	charging assumptions and the potential for double counting in IR-10 parts (a) and (c). NSPI has indicated that the modeling of EV peak and energy impacts will be adjusted over time to account for E1 and other managed charging programs as they are rolled out and as EV penetration increases, leading to more actual data being available to inform load forecasting. However, NS Power would need additional details on the proposed demand response program to better understand the impact to peak demand (as it relates to EV managed charging).
E1	On July 8th, 2022, E1 requested that NS Power share the 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 resources build-out selected by the model. E1 reiterates this request.	NS Power will share the yearly load forecasts for the EV and heat pump load forecasts as part of the output of the final modeling results.
E1	On July 8th, 2022, E1 requested that NS Power provide the adjusted DSM cost streams to E1 with all formulas intact. E1 reiterates this request. E1 requests that NS Power provide details on how inflation has been applied to DSM relative to other resources.	NS Power confirms that the cost streams, with the formulas intact, will be provided. The financial assumptions, specifically inflation, are provided on pg. 4 of the updated evergreen IRP assumptions (IRP Evergreen - Updated Assumptions (nspower.ca)).

E1	On July 8th, 2022, E1 requested additional clarification around the assumptions relating to the hybrid-peak mitigation approach 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 Nova Scotia Power's 2022 Load Forecast. Does the "Hybrid Peak Mitigation" scenario remove the "Nova Scotia Power HP Peak (MW)" peak impact, the "E3 HP Peak (MW)" peak impact, or does it assume a different impact? Please explain. In response to this, NS Power stated the following: *"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."* This response does not adequately describe the level of detail needed to model this scenario, or for stakeholders	The Hybrid-peak mitigation scenarios differ from current policy and trends scenarios in that it assumes back up heating sources (example: oil heating) are retained for use during the coldest periods. As compared to current policy and trends, the hybrid scenario has a larger proportion of dual fuel heat pumps to be used during the coldest periods and has the effect of reducing peak requirements (please refer to pg. 18 of the February 2023 IRP Action Plan Update: link).

	to assess the environmental/customer/cost implications of this scenario. E1 reiterates the request for additional clarification relating to the hybrid-peak mitigation approach and how it differs from the "Current Policy and Trends" scenario.	
E1	Several scenarios in the January 2023 IRP Evergreen Update have high levels of non-firm resources. For example, CE1-E1-R2 contains approximately 5500 GWh of wind and 1000 GWh of non-firm imports by 2030, just under 50% of energy requirements. Similarly, CE1-E1-R2-HDER appears to allocate approximately 5000 GWh of wind, 1000 GWh of solar, and 1000 GWh of non-firm imports by 2030 (approximately 60% of energy requirements). Other than the modeled UCAP Planning Reserve Margin (PRM), has NS Power completed any reliability studies to assess the feasibility of these scenarios? If not, when will this work be completed?	The increased level of non-firm resources, specifically variable renewable generation, and their impacts on reliability are supported by the wind integration studies that are currently underway by the NS Power Transmission Planning Team (IRP Roadmap Item 2 - Wind Integration Studies). The studies assess required changes to the transmission system required to maintain stability and reliability to maximize invertor-based resources. An update on the wind integration studies and the results to date can be found on slides 36 – 38 of the February 2023 IRP Action Plan Update on the NS Power IRP website (PowerPoint Presentation (nspower.ca)).
E1	In the January 2023 Evergreen IRP Assumptions, NS Power states that the fuel pricing service providers and approach were consistent with the 2020 IRP. Please confirm when the fuel prices used in the January 2023 IRP update were last updated. On page 40 of the January 2023 IRP Updated Assumptions, NS Power shows an estimated hydrogen fuel price trajectory. E1 requests that NS Power provides the source for both the domestic and import price trajectories. E1 also requests that NS Power provides clarity around the assumed source of the hydrogen imports for all methods of transport	The fuel prices were updated as of the timing of the release of the evergreen IRP assumptions in July 2022. The sources for the hydrogen pricing are included on slide 39 of the Updated Evergreen IRP Assumptions. The hydrogen use case assumes a 70% blend in CT units will be achievable by 2028. This is assumed to be the maximum blend until 100% hydrogen CT capable units are enabled in 2035 (current assumptions based on best available information).

	(truck/pipeline/other) and detail the estimated cost of storage. Please provide further detail on NS Power's hydrogen use case. E1 wishes to better understand how NS Power plans to incrementally increase the use of hydrogen over time, and better understand the blending assumptions/requirements, if any.	
E1	In relation to Supply Additions E1 submits the following questions: - Has the cost of light oil fuel storage been included in the cost estimates for all facilities that have fuel switching? What capacity of oil will be stored at each site? - Can NS Power provide a reference with links to the NREL Annual Technology Baseline (ATB) geothermal capital cost estimate and confirm which enhanced geothermal system (EGS) model was referenced (Deep EGS/Binary, Deep EGS/Flash, NF EGS/Binary, NF EGS/Flash, etc.)? - NS Power proposed input for geothermal ($7,644 CAD/kW) appears to be derived from the 2025 NREL ATB capital cost estimate for geothermal – hydro/flash (non EGS) advanced technology innovation scenario[11] which specifies a cost of $5697 USD/kW, or $7644 CAD/kW[12]. The advanced scenario is subject to substantial drilling and EGS advancements that may or may not be achieved. As such: ○ Please confirm if E1's understanding of this proposed input is correct.	The cost of additional fuel storage has not been included in the cost estimates and will be assessed at the project economic analysis level. Based on previous NS Power project analyses, this cost is not significant relative to the assumed cost of new peaking gas facilities. References to the NREL resource are included in the assumptions slide deck. The capital values will be updated to reflect deep EGS/binary (will increase from what is currently reflected in the assumptions deck). NS Power can confirm the ITC is modeled as described in the assumptions update (ITC phase out). The capital cost for the Atlantic Loop that has been included in the assumptions is reflective of the portion of the capital cost attributable to rate payers. For any and all updates on ECEI projects, including the reliability tie and discussions re: imports, please refer to the 2022 IRP Action Plan Update on the NS Power IRP website. The statement *"NS Power is reviewing IRP assumptions for Geothermal in the context of information released by the province in Fall 2022"* from NS Power refers to

	- If E1's understanding is correct, please provide justification for using the advanced scenario as an input estimate over using the moderate or conservative scenarios as input estimates. - If E1's understanding of the geothermal capital cost estimates is correct, why was non-EGS technology used as the capital cost estimate basis when EGS is listed as the desired sub-technology? For reference, the geothermal – Deep EGS/Flash advanced scenario shows 2025 cost estimate of $11,587 USD/kW ($15,547 CAD/kW), $15,829 USD/kW ($21,239 CAD/kW) for the moderate scenario, and $19,561 USD/kW ($26,246 CAD/kW) for the conservative scenario. All of which are more than double the proposed input estimate. - Given the differentials in capital costs listed above, will NS Power commit to re-examine its proposed evergreen input for geothermal capital cost? - In the January 2023 Evergreen IRP Assumptions Update, NS Power notes that the investment tax credit is subject to fade out over time. The 2022 Fall Economic Statement further clarifies this 'fade out' period as follows: *"The Clean Technology Investment Tax Credit would be gradually phased out starting with property that becomes available for use in 2032 and would no longer*	Geothermal information provided by the Province through a lunch and learn supported by Net Zero Atlantic. The discussion outlined the geothermal potential in NS and discussions around deep EGS that are now reflected in the capital cost assumptions.

	be in effect for property that becomes available for use after 2034. The credit would gradually phase out with a credit rate of 20 per cent in 2032, 10 per cent in 2033 and 5 per cent in 2034." - Please confirm if the investment tax credit was modeled as described in the 2022 Fall Economic Statement. If the tax credit was not modeled as such, will NS Power commit to modeling the investment tax credit as described in the 2022 Fall Economic Statement in the next update? - Has NS Power adjusted the Atlantic Loop cost estimates based on recent inflation and input cost escalations such as materials and labour? - In the 2022 Annual Capital Expenditure (ACE) Plan, NS Power stated in their response to Consumer Advocate Information Request 2(a), "each ECEI capital submission described in the 2022 ACE Plan will be supported by relevant economic and technical analysis to demonstrate the requirement for the project in the context of the current planning environment." One of those ECEI items was the New Brunswick reliability tie. o What is the estimated build time for the New Brunswick reliability tie? o In what year does NS Power anticipate a capital filing being submitted for this project?	

	- Please provide an update on what planning work has been completed to date on this project. - Are there any costs that NB Power is expected to pay related to the reliability tie? - In a reply comment to Heritage Gas (now Eastward Energy), under the New England Import Assumptions, NSPI stated that there were no commercial discussions with New Brunswick on the reliability tie. Are there now discussions? - Does the cost estimate of the Atlantic Loop include the long-term firm transmission rights needed on the New Brunswick system? - On page 16 of the January 2023 IRP Evergreen Update, NS Power stated, *"NS Power is reviewing IRP assumptions for Geothermal in the context of information released by the province in Fall 2022".* E1 requests that NS Power clarify what information/documents are being referred to in the statement above.	
E1	In relation to Renewable Integration, E1 submits the following questions: - In several Atlantic Loop scenarios there would be a need for the NB intertie to be used to balance wind, which would require dynamic scheduling capabilities on the intertie. Is this being considered for the reliability tie or Atlantic loop?	The existing NB Intertie does not allow for dynamic scheduling to balance wind generation as there are no firm capacity commitments with NB. The same would be true for the reliability tie as it is intended to reinforce the existing NS-NB intertie and would not provide access to firm imports. However, extension beyond the reliability tie as part of the Atlantic Loop is intended to provide

	- How are the costs of renewable curtailment considered in PLEXOS? I.e., are renewables providers paid for curtailed energy? If there are multiple scenarios considered, please describe all of them and when they would apply.	access to firm imports and would enable dynamic scheduling capabilities to balance wind. PLEXOS considers the costs of curtailed wind for IPP wind generation in the model (those who have a power purchase agreement with NS Power). All generation for the IPP wind producers is paid whether the generation is used or curtailed.
Eastward Energy	Slide 17 of the Draft Modelling has now indicated the conversion of three coal units to HFO in all scenarios, and slide 45 of the Assumptions shows sustaining capital for Lingan units 1, 3 and 4 on oil. It would be beneficial for NSPI to confirm that the capital and operating costs regarding the HFO conversion supply option on the Assumptions slides 17 and 18 are in relation to the conversion of Lingan units 1, 3 and 4, and to indicate whether the costs account for any additional anticipated HFO storage requirements.	NS Power confirms that the HFO Operation capital and operating costs found on slides 17 and 18 of the updated assumptions reflect the HFO conversion estimates for Lingan Units 1,3 and 4. Potential additional HFO storage requirements are not included in the current evergreen IRP conversion cost estimates; any potential additional requirements for HFO storage will be determined based on the unit utilization seen in the IRP analysis and other studies and economic analyses.
Eastward Energy	Slide 32 of the Assumptions refers to the costs for the Reliability Tie which appears to be a part of all scenarios studied. To understand the impacts of the Tie, Eastward Energy suggests a sensitivity run not including the Tie would be helpful as part of the updated modelling.	Since the Reliability Tie was included in the 2020 IRP Action Plan, NS Power had incorporated it into all scenarios in the evergreen IRP. However, to assess the Reliability Tie sensitivity recommendation, the No Atlantic Loop scenarios allow the Reliability Tie to be economically chosen as a resource meaning that it is not fixed in the model. In addition, there are no constraints requiring the Reliability Tie build by a certain date in the No Atlantic Loop scenarios. NS Power will update the assumptions.

Eastward Energy	As in the prior assumptions, NSPI states in slide 34 of the Assumptions deck that the energy and capacity cost associated with the Atlantic Loop will be based on updated New England market forecast, adjusted to represent Quebec import source. Eastward Energy is unclear on what price adjustments are required to "represent Quebec import source" in relation to either energy or capacity that may be sold to Nova Scotia based off of New England market forecasts and believes some further clarity of the intent of this reference would be useful.	NS Power is using a third-party, fundamental long-term forecast of energy and capacity pricing in the NEPOOL market to proxy HQ energy and capacity pricing. These forecasts are adjusted for foreign exchange and transportation costs to reflect a landed NS price. An adder has been applied to these monthly estimates, across the entire horizon, to reflect a market premium for clean energy. NS Power has provided import cost curves that reflect forecasted seasonal average Atlantic Loop energy pricing (please refer to the following location on the NS Power IRP website for the data and charts: Document Library → 2022 Evergreen IRP).
Eastward Energy	Eastward Energy notes recent comments from Hydro Quebec regarding the pressure it is facing to meet its own peak demand and its need for significant new capacity to meet its own growing electric demand during the next ten years. It would be helpful to understand how NSPI has factored this into the ability to obtain capacity from Hydro Quebec via the Atlantic Loop and how this is anticipated to impact potential pricing.	Please refer pg. 13 of the February 2023 IRP Action Plan Update (link) for updates on continued discussions with Hydro Quebec. Discussions with Hydro Quebec leading into the evergreen IRP modeling work have not warranted a limitation of the available capacity for NS Power. NS Power notes that the capacity expansion model is able to optimize capacity purchases from the Atlantic Loop in the range of 50 to 550MW. This provides insight into the tradeoff between firm capacity purchases and domestic capacity resources (i.e. new gas units or fuel conversions).
Eastward Energy	Eastward Energy notes that slide 25 of the Assumptions refers to distributed energy resources and that the Draft Modelling shows significant reliance on non-dispatchable resources. As such, it would be useful for NSPI to provide an update on how the IRP modelling captures the potential transmission and distribution upgrade costs that the energy transition will impose on the system and the cost assumptions that NSPI is using in this regard.	Similar to the 2020 IRP, NS Power includes nominal interconnection costs (example: short spur line to connect to the system) for supply side resources. The assumptions also detail the system upgrades required to allow higher levels of dispatch for non-dispatchable resources including energy storage, synchronous condensers, and the Reliability Tie.

Eastward Energy	In the various Draft Modelling scenario charts provided it is difficult to fully differentiate the various grey-coloured gas supply options from each other as the grey shading is quite similar. Eastward Energy would appreciate if NSPI could give each gas option a separate colour and provide a re-coloured version of the charts for the results of each of the model runs that had been provided in the Draft Modelling results.	Along with the final evergreen IRP modeling results, NS Power will provide the data tables for each data set displayed on the charts. The data can be used to compare back to the charts for a more detailed review of the information.
Ecology Action Centre	Can you run one or more of these scenarios with no Biomass for electricity? I know it's firm and dispatchable, but it is not truly green in the EAC's environmental lens. Can we substitute with increasing wind, solar, and energy storage to match the subtraction of Biomass? The Evergreen IRP document mentioned using 1 MW BESS for each 2 MW wind or est. 3-4 MW solar PV? How much would that change the NPV in all of these scenarios? This small change would help gain a lot of public support across all Nova Scotia, even within the silviculture industry and my fellow tree planters.	NS Power's existing resources are modeled in all scenarios and generation is modeled based on the current environmental policies in place, including the contribution of this generation to RES compliance. In addition, PHBM is a cogeneration facility providing steam supply to a customer, which would require the continued generation in the PLEXOS model to maintain. The ability of BESS to integrate wind/solar is variable and does not reflect the capacity and energy required to replace a dispatchable resource. The PLEXOS model co-optimizes capacity and energy sources as part of each capacity expansion scenario. The Draft Results show significant quantities of new variable renewable energy being added to the system, primarily in the form of wind, for energy while new capacity is primarily added in the form of gas generation or storage. Replacing a dispatchable generation source (biomass) would likely require a similar combination of these two resources. Please note that the ratio of BESS to wind and solar refers specifically to integration constraints. Please see slide 50 of the updated assumptions slide deck for the noted reference (example provided: 1MW of BESS and

		synchronous condenses enable 2MW of incremental instantaneous wind dispatch capability). This is not saying that 1 MW of BESS and 2 MW of variable renewables can replace any certain quantum of dispatchable thermal capacity but rather reflects wind dispatch constraints.
Ecology Action Centre	I wonder if solar PV "tracking" sub-technology (pg 18 of 53) is a general reference to single axis seasonal tracking solar PV costs, but wouldn't simpler designs or non-tracking bifacial panels be cheaper when paired with energy storage (reference 7)…this would also make it more useful for the winter evening peak or other expensive times of day for fuel. Germany is intentionally installing some of its solar PV West-facing. This is directly related to Planning Reserve Margin and Capacity, as was indicated in the two figures (pg 28 of 53) on average and marginal ELCC solar load as discussed in the Evergreen IRP documents. Assumptions matter in representing each technology fairly, so I am curious if there could be a co-benefit of this assumption of either co-located or paired-with-storage down the wire.	NS Power's Resource Options Study, as part of the 2020 pre-IRP materials, considered this. The following was demonstrated: - 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 is considered These assumptions have been maintained in the evergreen IRP work.
Ecology Action Centre	Energy storage anywhere on the grid doesn't have the same capacity factor/utilization rate, and some grid services that big batteries provide are more valuable on the grid than others, but I don't know if the PLEXOS model can simulate the full value of each BESS installation in various configurations across the grid, both in geography, and accessing economies of scale on some sites. This matters when it comes to attracting capital and successful projects on the BESS side, and with more profitable wind farm developers when they don't get curtailed in high percentages. (reference 5 and 6)	NS Power agrees that the value of a BESS can be influenced by its location on the grid. This type of study is outside of the scope of long-term capacity expansion modeling but is addressed at the project level analysis. The PLEXOS model reflects the NS Power transmission system in a simplified nodal representation. For modeling purposes, BESS units as economically selected by PLEXOS are located on a load participation factor basis. The BESS units are all 4-hour duration and provide identical services. There are no economies of scale assumed.

Ecology Action Centre	Run model scenarios without natural gas/HFO expansions after 2030? That's several tens of millions of non-existent thermal (fossil and biomass pg 44-47) operating expenses, which could buy a lot of battery capacity, scaling out in multiple phases as is being done in Australia. With future forward statements as many are making around the world, I am glad to see considerations of Hydrogen for long term storage-only; with Ammonia (reference 3) peaker plants designed for longer periods without wind/solar but used sparingly. Why not use a Hydrogen combustion plants for high ramp rates, and paired with Hydrogen fuel cells for baseloads for 24-78 hour gaps in wind, can the models then demonstrate capturing and using the Hydrogen waste heat for district heating in buildings/greenhouses, or even something as simple as heating a gas station or keeping the pavement clear of snow on Halifax walking paths like they do in Denmark? (i.e. with heated asphalt – compared to paying for snow removal). How do we make smart cities? We recommend having a few natural gas plants as emergency backup but don't intend to produce half as many GWh with them, some scenarios could approach less than projected.	All resource supply side options are made available in the model and are chosen to reflect a resource mix that provides the lowest cost plan on a net present value basis. Included in this are capital and operating costs as well as the costs and restrictions associated with environmental policy. Given the current limitation on Li Ion batteries (i.e. generally 4-hour duration or less) to provide firm capacity as grid penetrations of variable renewable generation increase, longer duration storage or dispatchable generators are required to maintain system reliability. NS Power has offered longer duration (i.e. 12 hour) storage resources to the model but has not yet seen them selected in any IRP scenarios. NS Power appreciates the suggestion re: hydrogen fuel cells. NS Power's current understanding is that the size and technology advancement for hydrogen fuel cells is limited in its ability to support utility scale generation. The draft results indicate that new combustion turbines, when economically chosen, operate at low-capacity factors to provide peak demand support and support periods of low renewable generation output. NS Power believes this is aligned with the anticipated utilization presented by EAC in this comment.
Ecology Action Centre	I am very interested in knowing how many TWh to power an entire province of electric vehicles by 2030 – 2040? What assumptions of how many vehicles on the road was in the E3 scenario? 14 TWh seems surprisingly low for	The Electric Vehicle (EV) load impact curves, based on the electrification strategy work completed by E3, informs the load forecast. Any value in managed charging or other

	future electrification-based power grid, it would likely be double or more – all things considered – for personal transportation, and potentially up to triple if including freight transportation, unless the recharge/refueling recommends using transmission lines for efficient distribution, reducing losses where at all possible domestically. This would mean serious upgrades to the grid, and many more TWh on the grid, even if just freight transport only. - The following are just examples of existing technologies that can easily change these assumptions. - 2030: With 30% Gasoline PHEVs, 50% BEVs, and 20% FCEVs? - 2040: With 30% Hydrogen PHEVs, 50% BEVs, and 20% FCEVs?	are noted as a reduction in load requirements (not modeled as a source of firm capacity). The 2022 Load forecast Report incorporates an assumption of 75,000 EVs on the road in NS by 2031, mostly made up of light duty vehicles (LDVs). The EV forecast reflects the outcomes of a stock rollover model prepared by E3 that forecasts adoption with the aim to meet provincial and federal net zero targets by 2050 while also meeting the Provincial and Federal mandates of 30% of vehicles sales from EVs by 2030 and 100% of vehicle sales from EVs by 2035, respectively. The total load forecast of approximately 14 TWh in 2050 also incorporates a cumulative 3 TWh of incremental Demand Side Management / Energy Efficiency which is added over the planning horizon. The ultimate impact on annual energy and peak demand depends on a number of factors however, including types of vehicles, access to charging, and charging behavior.
Ecology Action Centre	If I am reading this right, are you saying there would be 2.8 TWh that would be curtailed in this scenario in later years?	Yes, please refer to slide 18 of the Draft Results on the NS Power IRP website, which indicate that in later years (for scenario CE1-E1-R1), there would be approximately 2.8 TWh of curtailment of wind and solar in the later years. NS Power will provide additional reporting on curtailment with the final modeling results.
Ecology Action Centre	Why not add an 800MW / 2400MWh big grid battery and go from ~1-2T eCO2 a year to half of either respectively? Is there a fear of not getting enough capital for a project or global supply restrictions of Lithium? What would change these assumptions? Broader public support?	A standard 4-hour duration battery, sized at 800MW (3200MWh) would contribute approximately 200MW to firm capacity requirements (a 3-hour BESS as suggested would have less firm capacity value per the ELCC study results). As a result, while variable renewable energy curtailment could be lower (but not eliminated) with such

	*Note that 2.8 TWh would be ~319 MW at 100 CF (Capacity Factor), so I assumed a 40% CF to reach this 800 MW rated capacity that can be tweaked to the nature and scale and distribution of the potentially planned for 2.8 TWh of curtailments. This would only cost maybe $0.8 – 1B in batteries and seems like a missed opportunity to at a minimum stop burning biomass for electricity. Most of these scenarios are in the range of $16-28B NPV so it seems reasonable to include these factors in modelled scenarios. I note again in the comments that 1 MW BESS is about 2 MW of increased wind onboarding.	a large BESS installation, the system costs of BESS (capex + opex) plus other sources of firm capacity required to reach the planning reserve margin requirement would be cost prohibitive. As above, these trade-offs are considered in the PLEXOS mathematical optimization algorithm when identifying least cost portfolios. NS Power interprets increasing rates of curtailment as being reflective of the relatively lower cost of new variable renewables in the model when compared to the increasing costs of fuel and carbon price associated with thermal generation and the need to meet the 80% RES and coal phase out requirements. This cost disparity appears to result in economic curtailments as part of maximizing the availability of renewable generation to the system at higher load hours. Please note that the ratio of BESS to wind and solar refers specifically to integration constraints. Please see slide 50 of the updated assumptions slide deck for the noted reference (example provided: 1MW of BESS and synchronous condenses enable 2MW of incremental instantaneous wind dispatch capability). This is not saying that 1 MW of BESS and 2 MW of variable renewables can replace any certain quantum of dispatchable thermal capacity but rather reflects wind dispatch constraints.
Energy Storage Canada	*"All scenarios modeled incorporate the addition of significant capacity of variable renewables resources, which will require further study to understand impacts on system strength, stability, and operational considerations"*.	The 2019 PSC stability study evaluated the costs and constraints to meet the provision of essential grid services with the phase out of coal (large synchronous machines) and an increase in invertor-based resources. These essential grid services (ramping reserve/net following capabilities, system strength/short circuit ratio, MVAR support and synchronous inertia requirements)

	Energy storage technologies and projects – co-located with thermal or renewable generation facilities, or sited elsewhere on the system – can support system strength and stability while providing other valuable benefits to the system. In many jurisdictions with capacity and ancillary services markets, new energy storage projects and technologies are increasingly the most competitive option to provide said services. ***What assumptions are being made in the Evergreen IRP for the operational characteristics of short- and long-duration energy storage projects and technologies (with and without "grid forming inverters"), and synchronous condensers, as it relates to their ability to support system strength and stability?***	were modeled in PLEXOS as dynamic constraints (model will enable renewable generation integration if provision minimum values for these grid services are met). The outcome of the study identified new fast acting CTs as a requirement to meet ramping rates with the reliability tie or a 200MVA synchronous condenser and 200MW battery to increase installed wind capacity on the system (beyond 100MW). The study also identified renewable integration technology capital costs to support the IBR integration 2020 IRP assumptions. Following the 2020 IRP, NS Power revisited the integration methodology and has moved from requiring specific integration assets to implementing hourly dispatch constraints (based on the mid-electrification scenario from the PSC study). The model now assumes a certain level of hourly dispatch depending on integration assets available and allows the model to assess the economics of variable renewable energy expansion versus the need to curtail in certain hours to support system stability. The model also enforces a max allowable penetration of variable renewable generation in any given hour, which relaxes over the modeling horizon to reflect advances in IBR technology with the ability to better support grid services in the future. To better understand the system requirements to enable large penetrations of variable renewable generation, NS Power is progressing the wind integration studies (please refer to slides 36 – 38 of the February 2023 IRP Action Plan Update for an update on the results to date of the wind integration studies – link). While work is still underway on these studies, early findings have demonstrated that reduction of inertia on the system

		with the retirement of thermal generators can be met by other sources of synchronous inertial response, which includes the fast frequency response provided by grid scale batteries. However, results to date indicate that synchronous condensers close in proximity to the variable renewable resource is required to support system strength (source of reactive power to maintain appropriate voltage conditions on the grid). Further analysis, review and study of emerging technologies to support this is ongoing.
Energy Storage Canada	In the absence of energy storage projects and technologies, curtailment of variable renewable electricity generation generally increases as penetrations of variable renewable electricity generation increase. "*In addition to the max hourly dispatch constraint, NS Power will also impose a maximum instantaneous penetration constraint, which imposes a maximum allowable instantaneous penetration of variable renewable energy constraint in any given hour*". Energy storage technologies and projects - co-located with thermal or renewable generation facilities, or sited elsewhere on the system – can be a cost-effective option to reduce curtailment and transmission congestion while providing other valuable benefits to the system. ***What assumptions are being made in the Evergreen IRP to consider the ability of energy storage projects and technologies to manage excess generation or reduce transmission congestion in the place of curtailment?***	NS Power will be providing wind curtailment values for each scenario modeled as part of the evergreen IRP work. Battery storage options are made available as a supply side resource in the model. The model will assess the value of adding additional storage versus curtailing wind in order to minimize modeled system costs. BESS representation in the PLEXOS model includes the full value stack of applicable services from a hourly generation dispatch model perspective (energy arbitrage including charging from energy that would otherwise be curtailed, firm capacity value, operating reserve provision, interactions with variable renewable energy via reduced curtailment). Other BESS value services related to system strength and stability have been captured to the extent currently understood via the Renewable Integration constraints.

	The presentation of information in the Results Workshop that shows curtailment for each scenario in each year, and that discusses curtailment and transmission congestion temporally and spatially would be very valuable to better understand how and where energy storage projects and technologies could be deployed in future to the benefit of the system.	
Energy Storage Canada	The shift from thermal to renewable as the single largest electricity supply source brings significant contextual change for the assessment of resource adequacy in the province. Specifically, the timing and duration of tight supply hours can be expected to change in future. Energy storage projects and technologies are dispatchable capacity sources that increase resource adequacy at the system-level, and increase a thermal or renewable generation facility's contribution to resource adequacy at the project-level, year-round. ***ESC respectfully requests the presentation of information at the Results Workshop discussing how the timing and duration of tight supply hours will evolve from present in the various scenarios being modelled***. ESC is particularly interested to understand how the Effective Load Carrying Capacity (ELCC) metric does or does not remain the most suitable measure of resource adequacy over time from Nova Scotia Power Inc.'s perspective, especially as related to the interaction between energy storage and other resources.	The PRM and capacity value study (completed for the 2020 IRP) assessed the ELCC of Variable Renewable Energy (VRE) resources and storage. The results produced ELCC curves, reflecting how increases in penetration impact the firm capacity value. For storage specifically, various duration options were assessed. This report also assessed the diversity benefit of paired storage and wind or solar, wherein the contribution to PRM from the paired resource is greater than the sum of their individual contributions. These ELCC curves and the diversity benefits of paired resources are now reflected in the Evergreen modeling as part of NS Power's efforts to continuously improve its PLEXOS model. NS Power agrees that the existing ELCC curves for different penetrations of storage and VRE may change as the system configuration changes over the long term. The existing ELCC values are suitable and representative of their true values. This was confirmed during the 2020 IRP where system resource adequacy was confirmed via LOLE analysis on a range of decarbonized resource plans (see 2020 IRP Final Report section 6.6 – Reliability).
Energy Storage Canada	"*Demand Response (DR) programming, as modeled in the 2020 IRP, are now included in the 2022 Load Forecast and being implemented as part of the IRP Action Plan.*	The DR included in the load forecast is based on the aggregate value of the DR related programming and is based on the model in the 2020 IRP, which is being implemented via the IRP Action Plan. The portfolio is

	Accordingly, DR as a candidate supply side resource will not be tested in the 2022". ***To what extent is it (or could it be) assumed that energy storage technologies and projects are contributing to the DR being modeled in 2022?*** Furthermore, the electrification scenarios consider increasing penetrations of electric vehicles on the grid. ***What is the equivalent cumulative nameplate capacity of the energy storage that the electric vehicles assumed to be in operation represent? To what extent is smart charging assumed to be a form of DR? Does the model consider electric vehicle battery discharging as a source of firm capacity (and/or grid services)?***	assumed to include Direct Load Control programs (such as residential water heater controllers), Commercial and Industrial (C&I) curtailment, and Critical Peak Pricing (CPP). The Electric Vehicle (EV) load impact curves, based on the work completed by E3 for the 2022 Load Forecast Report, informs the load forecast as well. There are assumptions for managed charging which are already incorporated into that forecast, as detailed in the Load Forecast Report. Assumed value from managed charging is reflected as a reduction in load requirements. This directly reduces the capacity requirement for the system (including reduced Planning Reserve Margin). Specific to charging behavior, the peak impact assumes that 70% of charging behavior is managed by NS Power (including vehicle grid integration smoothing) and 30% of charging is unmanaged. The 2022 Load forecast is based on an assumption of 75,000 EVs on the road in NS by 2031, mostly made up of light duty vehicles (LDVs). As referenced in the 2022 Load Forecast, the EV forecast reflects the outcomes of the EV stock rollover model prepared by E3 that forecasts adoption with the aim to meet net zero targets by 2050 while also meeting the Provincial and Federal mandates of 30% of vehicles sales from EVs by 2030 and 100% of vehicle sales from EVs by 2035, respectively. The ultimate impact on energy sales and peak demand depends on a number of factors however, including types of vehicles, access to charging and actual charging behavior.
Kristen Overmyer	Assumptions, pg. 16:	The objective function for NS Power's long-term planning studies is the lowest long-term electricity system cost;

	Final bullet point states, "For the evergreen IRP modeling assumptions, the capital costs of qualifying clean energy/storage technologies will reflect the impacts of the ITC during eligible years." The credit is 30% of the capital costs of investment. Recommendation: At a minimum, the amount of this credit reflected in such technologies, where applied, should be reported as a separate line item for the scenario and not simply omitted and forgotten. The consumer pays for the credit through their taxes provided the credit does not increase the national debt. Depending on the average, provincial per capita utilization of the credit as compared to other provinces, consumers in a province may end up paying more or less than the actual credit amount through their taxes. Should you disagree, please provide evidence and argument as to why this should not be done.	assessing the impacts of broader tax policy outside the electricity system are not in scope for this analysis. NS Power notes that other tax treatment effects such as differing capital cost allowance rates are also considered in the IRP model. With the capital cost assumptions provided and the ITC criteria made public, those with an interest in quantifying the potential impacts of the ITC can do so with the results of the IRP analysis.
Kristen Overmyer	Recommendations: Revise the renewable energy cost trajectories to accurately reflect recent changes in world economic conditions and to account for an updated and more realistic understanding of economic factors going forward. Check the revised trajectories against other data and articles that also forecast this information. A harmonized combination of the information from disparate sources may be in order and would provide data for worst and	The capital cost estimates are based on public sources, where available. NS Power adjusts costs to incorporate foreign exchange and published actual CPI between base year and 2022. From a capacity expansion modeling perspective, if the relative difference in costs between candidate resources remains consistent, the resource portfolio that generates the lowest cost plan will not change. NS Power acknowledges the comment and will add a 'High Renewables and Storage" capital cost scenario to

	best case projections, both of which can be modeled to inform decisions. Should you disagree, please provide evidence and argument as to why this should not be done.	assess how meaningful higher capital costs impact expansion decisions for these types of resources.
Kristen Overmyer	Recommendation: Quantify and include the impacts of curtailment on the levelized cost of wind energy for the model scenarios where it is present. Should you disagree, please provide evidence and argument as to why this should not be done.	PLEXOS does not consider levelized cost of energy in its mathematical formulation for capacity expansion decisions – this graphic is for informational purposes only, and is presented in level-real dollars (i.e. without consideration of inflation). NS Power agrees that the LCOE's presented assume no curtailment. As LCOE is not a direct modeling input, NS Power will not be quantifying the impact of curtailment on this metric. The PLEXOS capacity expansion module (PLEXOS LT) considers the impacts of wind curtailment as part of the optimization. NS Power accepts the recommendation to provide additional renewable curtailment data; this will be provided with the final modeling results.
Kristen Overmyer	Under "Capacity Imports" the Assumptions state, "No access to near-term firm imports over existing transmission**" At the same time under "RES Coal Phase Out" page 10 states, "Modeling will assume 1100GWh/350MW of new wind is on the system, anticipated to be procured via the Rate Based Procurement Program (100MW in service 2024, 250MW in service 2025)." Questions: 1. Do these two statements together imply that one of the three situations that follow must occur?	The NS Power System Operator will curtail wind on the system to maintain system stability when necessary. NS Power notes that the wind projects being added via the Rate Base Procurement process will be capable of providing ancillary services to the system, including Automatic Generator Control (AGC) which will allow them to support frequency and intertie schedule regulation. NS Power has provided updates on near-term firm import availability as part of its IRP Action Plan Update (please see slide 10 - PowerPoint Presentation (nspower.ca)).

	a. At a minimum, the 250MW deployment will have to be delayed until 2027 when the Reliability Tie is slated to be in operation. b. Addition of “A 200 MVA Synchronous Condenser and 200 MW Battery” (page 49) to the grid. c. Increased curtailment of wind energy if 1 and 2 not implemented. (“Wind and Solar capacity additions as optimized by PLEXOS in the Capacity Expansion Module will no longer require specific integration assets” page 50). 2. What are the reasons there is no access to near-term firm imports over existing transmission? (What issues prevented agreements from being struck?)	
Kristen Overmyer	Questions: 1. What are the current annual levels of wind energy curtailment for years 2021 and 2022? 2. Given the RT is not in service until 2027 and assuming no new domestic assets are added to the grid for balancing wind energy, what will be the annual increase in wind energy curtailment for the new 350 MW of wind generation if deployed prior to 2027 as scheduled? 3. Can NSPI provide evidence that the ML balancing service agreement is being used to mitigate NS wind energy curtailment as the agreement was designed to do. 4. Can NSPI provide evidence of past or existing balancing service agreements for import and export of	Responses to specific questions: 1. Wind curtailment data is not publicly available. 2. The current modeling horizon starts in 2025 and the earliest in-service date for the Reliability Tie is 2027. The evergreen IRP final modeling results will include the level of curtailment starting from 2025 until the reliability tie is in place. 3. EAA Section 5.8 Nalcor Balancing forms part of an available remedy to a variance amount under the EAA; it is not currently in effect. 4. NS Power regularly enters into short term energy transactions over the NS/NB tie. The terms of these transactions are confidential and are reviewed by the Board as part of NS Power’s Fuel Adjustment Mechanism reporting.

	energy over the existing New Brunswick interconnections? 5. Can NSPI provide evidence of negotiations for balancing service agreements for import and export of energy over the new RT? 6. If the inability to secure new firm import capacity over the existing NB interconnections is not limited by the existing capacity, how will adding more transmission capacity vis-à-vis the Reliability Tie change this?	5. Information related to ongoing negotiations, including for potential balancing services, is confidential. 6. Please see the February 2023 IRP Action Plan Update (PowerPoint Presentation (nspower.ca)) on page 10 for an update on NB Power import capacity availability. The business case for the Reliability Tie (standalone from the Atlantic Loop) is not based on securing firm capacity, incremental energy imports, nor balancing services, but rather it is based on improving the reliability of the existing NS/NB interface. This is anticipated to allow NS Power to reduce minimum online thermal generation and increase the contribution of the NS/NB interface to system strength and inertia under high renewable penetrations. The Reliability Tie also serves as the first segment of a transmission expansion to reach new energy or capacity markets (e.g. Hydro Quebec, NEPOOL).
Kristen Overmyer	Question: I surmise that issues such as these those in the foregoing paragraph may be at the heart of NSPI's inability to secure any new firm capacity agreements over the existing NB connection even though its 350 MW capacity appears to be underutilized at present. Would you be so kind as to comment? Recommendations: I consider the lack of AL region modeling to be a serious omission. Without it, we cannot be confident the assumption of a high ELCC (e.g., 98% originally for the ML) for the AL imports into Nova Scotia is not grossly	NS Power agrees that in addition to NS Power's own modeling on the Atlantic Loop in the evergreen IRP process, region-wide modeling is beneficial to understanding the benefits and impacts of the Atlantic Loop project. Such modeling was completed as part of the Atlantic Clean Power Roadmap which was led by Natural Resources Canada and included representatives from NS Power, NB Power, Hydro Quebec, and regional government bodies. Please see the 2021 IRP Action Plan (IRP Action Plan Update Jan 2022 - March Update (nspower.ca)) on slides 18 and 91 - 92 for additional details and references to the studies completed.

	overoptimistic. Until such modeling is performed or credible evidence and cogent argument is put forward in its place, I recommend that work on the Atlantic Loop be suspended. I observe that page 23 of the "Draft Results and Process Update 2023" states that due to uncertainties create by NS Bill 212, "the progression of the Atlantic Loop has been put on pause." I recommend that notwithstanding the resolution of these uncertainties, the Atlantic Loop remain paused until credible simulation for the AL region as a whole is completed and shown to be viable. Should you disagree, please provide evidence and argument as to why this should not be done.	NS Power notes that capacity and energy purchases over the Atlantic Loop are optimized separately in the PLEXOS model.
Kristen Overmyer	Questions: 1. What specific input from stakeholders has led to the addition of new wind and solar assets *not* requiring specific integration assets to mitigate curtailment? 2. Is the 'Mid Electrification' assumption appropriate in the near term (in and before the year 2027) for ascertaining an appropriate hourly dispatch constraint for dispatch limited renewables? If so, please provide supporting evidence and argument. 3. What evidence (research, white papers, etc.) can NSPI provide that would indicate that the said technological improvements permitting "very large penetrations of variable renewable energy" are reasonably anticipated?	Responses to Specific Questions: 1. Please refer to the IRP website, which includes stakeholder questions and responses related to renewable integration constraints, for both the 2020 IRP and the evergreen IRP process to date (2020 IRP Scenarios and Modeling Plan – Participant Comments; NS Power Responses to Stakeholder Comments for the evergreen IRP Assumptions/Modeling Scenarios/Early Insights). Updating the constraint in the IRP from an asset enabling approach to a dispatch enabling approach reflects not only stakeholder comments but better reflects emerging practices on renewable integration from other jurisdictions (i.e. where build is not restricted but instantaneous penetration of VRE is limited during known conditions resulting in weak system strength and stability).

		2. As discussed in the NS Power 2022 Load Forecast Report, the mid-electrification forecast is in close alignment with the new bottom up analysis completed by E3, which supports the basis of the load forecast assumptions. Given this, NS Power is confident the mid-electrification scenario is reflective of system load requirements and can therefore be used as the basis to identify system needs and constraints. 3. As an outcome of the 2020 IRP, the impact on the system with the influx of large penetrations of variable renewable generation is currently being studied. The initial results are demonstrating that system inertia can be supported in part by fast frequency response enabled by invertor based resources including new wind and battery storage. Results to date are discussed as part of the February 2023 IRP Action Plan Update (PowerPoint Presentation (nspower.ca)). The final results of the wind integration studies, once finalized, will be shared with stakeholders.
Kristen Overmyer	Questions: 1. What is the assumed (or demonstrated if available) accuracy of the various PLEXOS output variables (GHG emissions, cost, etc.)? 2. Can NSPI provide evidence that the PLEXOS models accurately simulate the NS grid's behaviour and if so to what degree? Recommendations: PLEXOS modeling scenarios that represent the Nova Scotia grid operating over two one-year periods (e.g.,	Responses to Specific Questions: 1. Plexos software simulation accuracy is dependent on the accuracy of assumptions supplied to the model. If all assumptions provided to Plexos at the time of forecast held true over the study period, actual system dispatch would closely mimic Plexos optimization, with achieved emissions and costs ending up at where they were forecast to be. As system parameters diverge from the forecast assumptions, emissions and costs may diverge from the forecast. The impact of system parameters changes on the achieved versus forecast costs and

	2018 and 2021) for which the resulting power generating mix, costs, emissions, etc. are known should be performed and compared to NSPI empirical results for those years. This should provide an indication of the PLEXOS models' accuracy, aid in making any model corrections and/or additions, and provide guidance on how to interpret scenario results. Should you disagree, please provide evidence and argument as to why this should not be done.	emissions is lessened by the flexibility of NS Power's fleet, illustrated by the interchangeability of the coal based generation, fuel switching, and imports flexibility. 2. Future system configurations studied in the IRP do not yet exist, so NS Power has no basis on which to validate accuracy of system dispatch optimization as forecast. NS Power models plausible future states of the system based on available performance data associated with future technologies.
Marine Renewables Canada	Considering the province's target to offer leases for 5 GW of offshore wind energy to support its green hydrogen industry, MRC respectfully requests that Nova Scotia Power Inc. (NSPI) dedicate a portion of the Results Workshop (week of April 3) to a focused discussion of: - Offshore wind, with topics including the following: key findings; modelling data gaps; and transmission system availability; and - Green hydrogen, with topics including the following: key findings; modelling data gaps; and operating characteristics of electrolysers (as it relates to the provision of grid services).	NS Power will discuss and review the final modeling results with stakeholders during the results workshop. Offshore wind and hydrogen CTs are both offered as candidate resource options in the model, and the workshop discussion will focus on how those resources are being selected in the various scenario results and their impacts on the resulting resource mixes.
Port Hawkesbury Paper LP	Slide 10 – NSPI assumes 100 MW of new wind in service by 2024. Is this assumption based on an analysis of the current status of the Rate Base Procurement Program projects? Absent such information, PHP suggests the 350 MW of new wind should be assumed to be in service in 2025, which is now proposed to be the first year in the planning horizon in any event.	Correct, this assumption (100MW of new wind in service by 2024) is based on our understanding of the projected in-service dates for the Rate Based Procurement portfolio. As noted, since 2025 is the first year of the evergreen planning horizon, a shift from 2024 to 2025 would not affect the evergreen IRP results.

Port Hawkesbury Paper LP	Slide 11 – Once the proposed provincial performance standards are passed in Regulations, PHP suggests that NSPI should hold a technical conference with stakeholders to explain the constraints and impact on NSPI so this can be fully understood by all parties.	NS Power held an IRP stakeholder engagement session on March 21 to review the IRP Action Plan update and included an opportunity for discussion and questions regarding evergreen IRP assumptions.
Port Hawkesbury Paper LP	Slide 12 – With respect to the potential cost impacts associated with the potential Clean Electricity Standard enabling a net-zero electricity system by 2035, PHP suggests that NSPI should ensure it models sensitivities so that NSPI can clearly identify the additional costs that would be associated with the imposition of such a new requirement in Nova Scotia and the specific changes to the resource plan that would be suggested as a result.	NS Power is proceeding with modeling based on the guidance provided by Environment and Climate Change Canada for proposed regulations for 2035 and beyond. NS Power is modeling both NZ2035 and NZ2050 scenarios to provide stakeholders with additional data on the impact of the potential NZ2035 regulations.
Port Hawkesbury Paper LP	Slide 13 – This slide indicates carbon cost offsets will be modeled at a price of $500/tonne. NSPI should: (1) provide further justification and support for this assumption and (2) ensure it models sensitivities to determine whether a lower carbon cost offset assumption would have material impacts on the IRP results, all other things being equal.	The direct air carbon capture (DACC) of $500/tonne is not included in all evergreen IRP scenarios. NS Power will be testing this as a sensitivity to understand whether this has an impact on the expansion plan or whether it simply results in higher costs. The evergreen IRP scenarios which do not include the $500/tonne cost will provide stakeholders with a broad range of results on carbon costs for 2035 and later.
Port Hawkesbury Paper LP	Slide 17 – Given that the draft modeling has now selected HFO conversion, NSPI should provide a further review and explanation of the validity of the capital cost and operating cost assumptions of coal units operated on HFO only, so that parties have confidence these assumptions capture all costs and are realistic since they are not validated in the assumption deck by third party independent sources.	NS Power notes that since these units are currently capable of operating on HFO, the anticipated costs to convert to HFO-only operation are relatively low.
Port Hawkesbury Paper LP	Slides 29-30 – NSPI states that it will use the Base DSM profile except in the case of DSM sensitivities. The DSM Program Costs appear to show very similar trajectories	NS Power can confirm that the costs are in alignment with the DSM profiles provided by E1.

	for cumulative energy and peak demand reductions, despite significant differences in DSM Program Cost across the Base, Mid, Base Plus and Modified Mid profiles. NSPI should review and report back to stakeholders confirming the potential reductions associated with each profile are consistent with the program costs.	
Port Hawkesbury Paper LP	Slide 33 – As noted the capital cost of the Atlantic Loop of $1.7B is in-line with the assumptions used in the 2020 IRP, which final assumptions were dated March 11, 2020. As this assumption is now almost three years old, PHP suggests use of a more current assumption with respect to the forecast cost to be funded by NS customers and/or the potential contributions from government for this critical major project? NSPI should provide further information and updates about the status in this regard and the full basis for this assumption.	The capital cost for the Atlantic Loop that has been included in the assumptions is intended to represent the portion of the capital cost attributable to NS Power customers. It is anticipated that contributions to the cost of the Atlantic Loop project will also be required from other participating utilities and from government funding sources.
Port Hawkesbury Paper LP	Slide 34 – NSPI states that the energy cost and capacity cost “will be based on updated NE market forecast, adjusted to represent Quebec import source.” Previously NSPI has indicated that fuel and market price assumptions are not able to be shared via the IRP Evergreen process. At page 3 of its August 5, 2022 comments, PHP noted that import pricing assumptions are a critical component of the evergreen IRP analysis, and if such pricing assumptions are not shared with stakeholders on a confidential basis, it is impossible for stakeholders to assess the reasonableness of such assumptions and their potential impact. PHP reiterates its request that NSPI share all available data on a confidential basis with counsel and consultants, consistent with the approach taken in prior IRPs, so that stakeholder representatives can satisfy themselves as to whether these critical assumptions are valid.	NS Power is using a third-party, fundamental long-term forecast of energy and capacity pricing in the NEPOOL market to proxy HQ energy and capacity pricing. These forecasts are adjusted for foreign exchange and transportation costs to reflect a landed NS price. An adder has been applied to these monthly estimates, across the entire horizon, to reflect a market premium for clean energy. NS Power has provided import cost curves that reflect forecasted seasonal average Atlantic Loop energy pricing (please refer to the following location on the NS Power IRP website for the data and charts: Document Library → 2022 Evergreen IRP). Given that Hydro Quebec is actively involved in the US Northeast via interconnections with ISO-NE (through Maine and NY-ISO), a NEPOOL proxy is a representative opportunity cost.

Port Hawkesbury Paper LP	Slide 49 – In the footnote on this Slide, NSPI states local integration requirements to be determined via specific System Impact Studies. In its August 5, 2022 letter, PHP commented as follows: "Following the April IRP workshop, PHP remains unclear as to the scope, status, and expected completion date of the various "wind integration studies" and "renewable integration studies" that NS Power states are currently in process. PHP appreciates that these studies will not be completed in time to further inform the modeling constraints for the evergreen IRP. However, given the importance of these studies to the future operation of NS Power's system, as well as the long-term impact of these studies on the IRP analysis and results, PHP requests that NS Power provide all stakeholders in this process with more detailed regular updates regarding each of the specific wind integration studies that are underway. This should include reference to their scope, status, and the expected timeline for completion and circulation to stakeholders for review." PHP continues to be unclear on the scope, status, and expected completion dates of the various wind/renewable integration studies that are currently in process, and again requests that NSPI provide stakeholders with clear and regular updates, including a current status update on these matters, as such studies have the potential to provide valuable insight into the integration of significant new quantities of intermittent generation on the NSPI system.	NS Power recently provided an update on the wind integration studies as part of the February 2023 IRP Action Plan update. Please refer to the update for more information on study results to date; the document can be accessed here (PowerPoint Presentation (nspower.ca)) and the specific wind integration study updates can be found on pages 36 – 38. Results to date on both the understanding of the impacts on inertia and system strength as an outcome of increased wind integration on the system have been provided in addition to a summary of next steps to finalize the results and report on outcomes.

Port Hawkesbury Paper LP	Slide 51 – NSPI states that with its refined approach, wind and solar additions are freely optimized by the PLEXOS capacity expansion module, and the dispatch constraint will have the impact of curtailing variable renewable energy in stressed conditions that have been shown to negatively impact system stability. NSPI also notes The Capacity Expansion module will consider the impacts of curtailment vs. other system constraints and the overall cost minimization objective. On this point, PHP repeats the following comment from its August 5, 2022 letter: “PHP appreciates NS Power’s confirmation that it will provide an analysis of the amount of wind curtailment in each scenario as an output of the Evergreen modeling. This analysis should be provided as part of the Draft Modeling Results and made available to stakeholders as soon as possible. As noted, it should also include comment on the manner in which this constraint would be expected to be applied to the various proposed wind projects. This will allow all parties a greater understanding in a timely fashion as to how the system can best economically mitigate the need for curtailment or to mitigate the economic impacts of curtailment.”	NS Power will provide variable renewable generation curtailment by scenario as part of the final evergreen IRP modeling results.
Small Business Advocate	NSPI has identified multiple changes to its resource planning assumptions related to the expected limitations on capital expenditures driven by Bill 212. These limitations are in place through the current (2022 – 2024) General Rate Application test period, and NSPIs current planning period being considered in the IRP begins in 2025. As such, while there is no specific overlap of the capital spending restrictions and the planning cycle, it would be informative to stakeholders and the Board to	The IRP assessment and the outcomes of the modeling are intended to reflect the least-cost resource mix and are independent of asset ownership and associated capital investment requirements. This is aligned with the overall objectives of the IRP analysis. NS Power will consider potential approaches to incorporating a reduced capital investment scenario into the PLEXOS model; further investigation is required. If

	understand how some form of a continued limitation on capital spend might impact the ability of NSPI to meet other policy objectives (e.g. coal phase out) or reliability in a decarbonizing grid. The SBA recommends that NSPI develop a sensitivity scenario that applies a limit on capital spending, so that Stakeholders and the Board can understand how the service portfolio would have to change if NSPI is unable to make the optimal investments suggested in the IRP. This analysis does not necessarily need to replicate the restrictions in Bill 212, but can be a simplified analysis to understand the directional impact such a restriction would have. If that functionality is not currently available in NSPIs models, we suggest a sensitivity be included in the next full IRP analysis.	not completed for the evergreen IRP, NS Power will assess if this could be completed in future studies.
Small Business Advocate	The changes to the policy environment discussed by NSPI highlight the need for the IRP analysis to provide insight on when alternative resource strategies need to be pursued. Many of the investments being considered in the IRP have long lead times, so it is important to know well in advance how delays in certain investments (such as the reliability tie) will require changes to other elements of the plan. NSPI has been responsive to similar comments from the SBA in the past, and has included a scenario where the Atlantic Loop is delayed by 5 years. This is a helpful sensitivity for understanding the tradeoffs, and the SBA encourages NSPI to look for other sensitivities that will help stakeholders and the Board	NS Power appreciates the feedback on the approach to scenario development as it relates to assessing a range of key sensitivities. NS Power will be adding additional sensitivities of interest as a result of the feedback received on the Draft Results.

	understand key decision points for resource strategies and when alternative are needed.	
Small Business Advocate	In our comments to NSPI in July 2022, we discussed the importance of continued progress on the relaibility analysis needed to evaluate the impacts of additional clean energy on the grid. The 2020 IRP 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). NSPI has not yet provided an update to stakeholders regarding these analyses. Given the Province's Rate Base Procurement and NSPI's continued planning around inverter-based resources, it is important to understand if the current planning strategy is sufficiently capturing reliability constraints.	Please refer to the February 2023 IRP Action Plan Update (pg. 36 – 38, PowerPoint Presentation (nspower.ca)) as it relates to the ongoing wind studies in support of further wind integration requirements. The results of the study work to date indicate that system inertia can be met by remaining thermal units and synchronous condensers in addition to fast frequency response from the Maritime Link, grid scale batteries and technology enabled by new invertor-based resources. The study results re: the impacts on system strength, however, indicate further study is required to address the impacts of poor system response following a system disturbance with increased wind integration. NS Power will continue to provide updates on the outcomes of the wind integration study work as it is available.
Small Business Advocate	With the potential limitations on the recovery of capital expenditures discussed above, it is conceivable that the balance of NSPI costs recovered from customers will shift between general rates and the fuel adjustment mechanism (FAM). We have seen this with the renewable energy purchases such as COMFIT and with the structure of the Maritime Link. Thus, SBA recommends that the output of the IRP should include information to stakeholders and the Board categorizing whether expenses are capital expenditures versus fuel or purchased power and the implications that the balance will have on customer costs and affordability. We request that NSPI tailor portions of the IRP analysis to communicate the impacts that the financial structure will have on customers.	NS Power will explore options to disaggregate total system costs into relevant groups to the extent available with the current model structure and as the process timelines allow.

Solar Nova Scotia	SNS would appreciate additional clarity and information on the results presented for solar electricity generation for each scenario to gain a more robust understanding. Namely, what are the results for the total nameplate installed capacity of solar electricity generation in years 2025, 2030 and 2035 (or in each year of the planning horizon) for each scenario? Please indicate the amount of capacity that is considered in categories: utility-scale; DER; DR; or other, and describe whether the model treats the category as serving load, or reducing net load. For the appropriate categories (e.g. utility-scale, DER, DR, etc) please comment how or if the output from these systems is treated as "RES-compliant". Please provide the percentage that each category contributes to the RES targets in years 2025, 2030 and 2035 (or in each year of the planning horizon) for each scenario. A graph in the Results Workshop that shows RES compliance per year over time by resource type (and including renewable curtailment below 0 on the y-axis) would be very helpful to understand how this target is being pursued and achieved for each scenario.	For the final modeling results, NS Power will be providing data tables for the installed capacity for each resource addition, including any solar additions. The load forecast used for the evergreen IRP is based on NS Power's 2022 Load Forecast Report and as a result, there is a net load reduction that is incorporated into all scenarios which reflects the assumptions for net metering included in that forecast. Beyond that load forecast input, solar additions in the IRP are treated as generation resources in the evergreen IRP modeling work; this enables more discrete reporting on incremental solar generation in the modeling results. For all scenarios, except in the case of the High DER scenario, solar candidate resources are offered as utility scale. The High DER sensitivity scenario models a higher deployment (ultimately reaching ~1500MW by 2050) of incremental rooftop solar to differentiate it from the base behind the meter assumptions included in the load forecast. Any generation from economically selected utility scale solar and DER solar from the High DER scenario is RES compliant. BTM solar embedded in the load forecast, as referenced above, reduces the amount of energy sales that must be RES compliant.
Solar Nova Scotia	SNS Members are experiencing growing consumer demand for combining battery energy storage systems with their behind-the-meter solar electricity generation. In other regions, "hybrid" solar electricity generation	The evergreen IRP model does not explicitly study a combination of behind the meter (BTM) solar and storage.

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<td>paired with battery energy storage systems is becoming mainstream. How is the Evergreen IRP model treating behind-the-meter solar plus storage, and hybrid solar-storage projects?</td>
<td>Utility scale battery storage is made available as a supply side option in the model. For capacity expansion modeling purposes, utility scale resources are lower cost than their BTM counterparts. Thus, BTM resources, alone or in combination, are generally not assessed from a supply perspective.

For utility scale storage and solar/wind, NS Power models a diversity benefit which increases their Effective Load Carrying Capability reflecting the synergies between these resources.</td>
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<tr>
<td>Solar Nova Scotia</td>
<td>What is the system summer peak in years 2025, 2030 and 2035 (or in each year of the planning horizon)?

How does the annual distribution of the tightest supply hours change in the scenarios from 2020, to 2025, to 2030 to 2035?

What is the Effective Load Carrying Capacity (ELCC) of the total installed solar electricity generation capacity during summer peak and/or the other tight supply hours?</td>
<td>The summer and winter firm peaks are provided in the table below for the most recent evergreen IRP assumptions. NS Power has included data for different combinations of DSM (Base+ DSM and Modified Mid DSM or MMDSM) and electrification loads that are being studied.

<table>
<tr><td>DSM Scenario</td><td>Evergreen IRP Base DSM</td><td>Evergreen IRP Base+ DSM</td><td>Evergreen IRP MMDSM</td><td>Evergreen IRP MMDSM</td></tr>
<tr><td>Electrification Scenario</td><td colspan="3">Current Policy and Trends</td><td>Hybrid Peak Mitigation</td></tr>
<tr><td colspan="5">Winter Firm Peak (MW)</td></tr>
<tr><td>2025</td><td>2,074</td><td>2,074</td><td>2,074</td><td>2,001</td></tr>
<tr><td>2030</td><td>2,232</td><td>2,218</td><td>2,208</td><td>2,103</td></tr>
<tr><td>2035</td><td>2,531</td><td>2,515</td><td>2,494</td><td>2,387</td></tr>
<tr><td colspan="5">Summer Firm Peak (MW)</td></tr>
<tr><td>2025</td><td>1236</td><td>1236</td><td>1236</td><td>1236</td></tr>
<tr><td>2030</td><td>1329</td><td>1320</td><td>1313</td><td>1313</td></tr>
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		2035 | 1493 | 1483 | 1469 | 1469 NS Power plans the system capacity to meet the firm peak and PRM requirements, which occur during the winter months. Please see slide 27 of the assumptions deck for the ELCC assumption for solar. After small initial penetrations, the ELCC for solar is essentially zero since solar generation does not coincide with system peak load hours (winter evenings). The ELCC calculation accounts for, among other factors, seasonal and hourly patterns inherent to certain variable renewable energy resources (such as wind, solar, or other dispatch limited resources).
Synapse	Slide 17 provides 2022 and 2030 values for the capital cost estimate input assumptions. Please provide not just the 2022 and 2030 data points, but actual annual values of the trajectory of costs, and the values used beyond 2030.	The source of the cost estimates is based on publicly available information provided by NREL (2022 and 2030 values; cost trajectories are based on NREL ATB Real Dollar estimates and converted to nominal trajectories based on inflation - Index | Electricity | 2021 | ATB | NREL).
Synapse	Slide 6. NSP should reconsider either the estimated peak load trends in the latter part of the planning horizon or add in a proxy demand response resource representative of anticipated TOU or CPP responsive peak load reductions. Slide 29 indicates that "DR as a candidate supply side resource will not be tested in the 2022 Evergreen IRP". However, both energy and peak load increases in the later years (beyond 2032) of the forecast horizon are significantly steeper than seen in the first decade, and are significantly greater than the mid-case load projections from the 2020 IRP. This increase in electrification load effects should be accompanied by the	NS Power has modeled multiple sources of demand response, including capacity reductions in the DSM forecast (cumulative reduction of 500MW by 2050), the 75MW of DR in the IRP Action Plan, and the demand response / peak reductions provided by electric vehicle smart charging which is inherent in the 2022 Load Forecast assumptions (which assume 70% of EV charging load is controlled by NS Power and shifted to off-peak periods). The combination of the three demand inputs above represents a substantial reduction to the firm peak that

	inclusion in modeling of demand response resources likely to arise. It is analytically inconsistent to minimize the development and modeled representation of future demand response alternatives that are reasonably, if not likely, to emerge in Nova Scotia, while more directly addressing estimated electrification increases. Electrification-driven energy and peak increases are in the updated assumptions, but no consideration is given for incremental demand response options. The presence of a full AMI buildout, the existence of TOU rates with the potential for continuing investigation of TOU rate options, the potential for distributed battery resources to participate as emergency demand response capacity, and the eventual presence of potential vehicle-to-grid battery alternatives indicates at least the technical potential for greater levels of demand response offered to the model. While estimating a cost range for such resources is not simple, there should be a mechanism in place to consider the effect of such resources if they prove less expensive than supply capacity buildout options present in the model.	would otherwise be seen from electrification load growth and is an analytically consistent approach to considering these uncertain future inputs. As a further sensitivity, NS Power is modeling the hybrid peak mitigation electrification scenario, which reflects a mix of heat pump adoption and retaining back up fuel sources (wood, oil, etc) for use during the coldest periods (winter peak). While the hybrid peak scenario results in a similar annual energy requirement as compared to the current policy and trends, it represents a significantly lower system peak demand. The expansion plan decisions in the mid-to-late horizon are known to be of lower predictive value. As such, NS Power's evergreen IRP process is designed to update the long-term planning models as and when material changes emerge. This could include additional DR that becomes more economically competitive against other supply side options (rising carbon taxes, higher commodity pricing and input supply costs, etc.).
Synapse	Slides 9 and 10: Please confirm the nature of the 80% renewable energy (RE) constraint in the model: does it linearly increase between now and 2030, or is 2030 the first year in which the model requires the increase in RE? NSPI states a RES of 80% "as a percent of total sales". Please confirm that this implies no consideration is given in the modeling for the environmental attributes	The minimum annual RES constraint is 40% through 2029; it increases to 80% in 2030 (2030 is the first year 80% RES is required). The statement "as a percent of total sales" is correct; the RES legislation is based on the percentage renewables of NS Power's sales. The behind the meter (BTM) solar generation included as a load reduction in the load forecast reduces total sales

	associated with behind-the-meter renewables (solar PV) that reduce NSPI total sales.	and accordingly the total annual amount of renewable energy required under the RES requirements.
Synapse	Slide 27 contains summary ELCC information for wind and solar resources. No battery ELCC values, demand response effectiveness, or "portfolio" ELCC information is provided. Please confirm how NSPI will address the known diversity benefits for ELCC purposes of a portfolio of resources, especially the combinations of system level battery, wind, solar, and demand response options to address capacity needs during short-duration "super-peak" periods in the winter (or other peak periods), and how the model will handle this. Can NSPI include sensitivity analyses for at least a few scenarios that show how the model responds when assuming a greater level of "portfolio ELCC" arising from potential future optimum combinations of demand response, battery storage, and winter wind and solar output (relative to values used in the 2020 IRP base assumptions)? If possible, please provide NSPI's observations and considered effect on IRP modeling (if any) of the severe cold event just seen on February 3-4, 2023.	All ELCC values are consistent with the 2020 Pre-IRP Planning Reserve Margin and Capacity Value Study, which can be found in the NS Power IRP site (20191018-NS-Power-Pre-IRP-Final-Report-updated.pdf (nspower.ca)). The Planning Reserve Margin and Capacity value study assessed the diversity benefit of paired solar and storage and wind and storage. NS Power recognizes this diversity benefit in the expansion modeling; this is an enhancement in the evergreen IRP model relative to the 2020 IRP. NS Power does not have data to support a higher ELCC than what was quantitatively assessed in the IRP, including the diversity benefits of paired resources. NS Power has provided information to the UARB regarding the Feb 3-4 cold weather event which can be reviewed under Matter Number M10987. NS Power does not anticipate this event will impact the current evergreen IRP analysis.
Synapse	The real cost of the Atlantic Loop is likely to be higher than the 2019 value used in the original IRP. Please explain what research or exploration NSPI has undertaken to confirm the prospective Atlantic Loop costs used in the modeling.	The capital cost for the Atlantic Loop that has been included in the assumptions is intended to represent the portion of the capital cost attributable to NS Power customers. It is anticipated that contributions to the cost of the Atlantic Loop project will also be required from other participating utilities and from government funding sources.

	Also, NSPI presents, in the results section, a delayed Atlantic Loop timing scenario (2035 in-service). Please explain if NSPI believes that 2030, rather than some future year, is a reasonable point-in-time estimate at this stage for a base period availability of the Atlantic Loop energy and capacity resource.	As discussed in the IRP Action Plan update (link), NS Power capital investment in the Atlantic loop has been paused, however, discussions to explore import opportunities have continued. Given this, using 2030 as the base assumption and testing the impacts of delayed timing (2035) for the Atlantic Loop provides a reasonable range of potential timing outcomes to assess the value of the Atlantic Loop to the NS Power system.
Synapse	Provide all results in Excel format for transparency and to ensure accurate data is available to all stakeholders. Provide data at the annual resolution (seen in the graphs) for energy and capacity by fuel and generation type. Small modular reactors are not a commercial technology. Please consider excluding SMR options in all primary non-Atlantic Loop scenarios and execute just a single sensitivity that does include this prospective technology.	NS Power confirms that the results will be provided in excel format following the release of the final modeling results, similar to the 2020 IRP. The lack of current commercial availability is reflected in the "earliest availability" assumptions (2035). SMRs have been noted as an emerging technology to support net zero 2035 and is important for NS Power to test them as a supply side resource as part of the evergreen IRP. With the exception of the Atlantic Loop which is based on known transmission technologies, many of the resource options that provide non-emitting firm/dispatchable capacity are currently emerging (e.g. Hydrogen, Natural Gas with Carbon Capture & Storage).