Category	Comment #	Comment	NS Power Response
Reserve Margin	CA-01 Consumer Advocate	Instead of a planning reserve margin of 21% of installed capacity (with downward adjustments to the effective capacity for wind and some other resources), NS Power was imposing a minimum reserve of 9% in ELCC terms. Our understanding was that one MW of ELCC would support one MW of firm load. We are unable to locate any documentation for the conclusion that reliable supply requires capacity with a cumulative ELCC of 109% of peak load. We suggest that NS Power should provide that derivation and identify what drives the need for an ELCC reserve margin of 9%.	The ICAP method, which produces a 20% PRM, accounts for both thermal forced outages and extreme weather than the 1-in2 peak. The PRM under the UCAP method, which counts thermal generators at their ELCC, only needs to account for more extreme weather than 1-in-2 peak, resulting in a lower UCAP PRM. The detailed derivation of the IRP PRM assumptions was presented in the Capacity Study which was completed during the pre-IRP stage and is available on the IRP website. The decision to constrain the model to the UCAP (ELCC) PRM, rather than the ICAP PRM, was informed by stakeholder feedback during the Assumptions stage of the modeling process.

Category	Comment #	Comment	NS Power Response
End effects	CA-02 Consumer Advocate	NS Power modeling end effects as the present value of 25 years of the 2045 revenue requirements. This may significantly distort the differences among cases. Holding post-2045 revenue requirements at the 2045 level for 25 years overstates the end-effects costs of the plans with large capital investments near the end of the modeling period, compared to plans dominated by higher fuel or other expenses. Request analysis of whether the differences in end effects among the initial IRP results reasonably reflect differences in costs between options. If the variation in end effects among cases appears to be correct, but the magnitude is overstated, NS Power should consider shifting to a shorter end effect period (e.g., 10 or 15 years), or eliminating it altogether.	For clarity, the end effects period is modeled as a perpetuity of the 2045 costs (not a 25-year period) The cumulative present value of the 25-year planning horizon with end effects is one metric for cost evaluation. NS Power agrees it is not the only metric to consider when assessing the modeling results. NS Power has provided additional metrics as outlined in the Terms of Reference and provided with the September 2 Findings release to allow for a robust consideration of the modeling results. Costs for investments for new resources are annuitized in Plexos based on the depreciable life of the asset and the appropriate discount rate. This process for calculating annualized build costs serves to minimize or eliminate this potential bias in the 2045 End Effects period (i.e. incurring the full capital cost in the year built). NS Power agrees that both metrics (25-yr NPV with and without end effects) have positive and negative attributes and that is why both are presented for all scenarios and sensitivities.

Category	Comment #	Comment	NS Power Response
Distributed Resources	CA-03 Consumer Advocate	We are concerned by NS Power's decision to ignore the costs for the distributed energy resources in cases 2.1B and 3.1B. Determining the value to customers of DERs (especially storage, which adds resiliency) is difficult, so it would be hard to estimate the net cost of the DERs. We suggest that NS Power be careful to indicate each time it presents costs for these cases to indicate that they do not include any allowance for BTM costs. Those BTM costs do not fit neatly into the NPVRR calculation, since they do not represent utility revenue requirements. Nor should the full cost of DERs comparable to the utility costs, since DERs (especially paired solar and storage) provide additional benefits, particularly resiliency. If NS Power decides to incorporate some BTM costs into its reported cost metric, we suggest using a modest placeholder value. If Plexos produces marginal hourly energy costs, those could be used for the assumed DER load shape. Otherwise, NS Power might use some appropriate forecast estimate (average fuel cost, monthly marginal energy cost).	NS Power has provided this information for all DER cases when presenting NPV results. NS Power's rate impact calculation provides additional insight into the impacts of the DER (x.xB) resource strategy results.
Metrics	CA-04 Consumer Advocate	it is very difficult to compare plans with divergent load forecasts. NPVRR may be low for cases with high DSM and high for cases with lots of electrification, since the NPVRR does not reflect the benefit of fossil fuels avoided by electrification. The other economic metric in the interim results, the partial generation cost per MWh, does not provide much information about rate effects.	Based on feedback respecting challenges associated with comparing scenarios reflecting differing load levels due to electrification, NS Power has provided a relative rate analysis with the draft Findings release to provide a better comparison across plans to understand implications for ratepayers.

Category	Comment #	Comment	NS Power Response
T&D	CA-05 Consumer Advocate	NS Power staff explained that the projection of revenue requirements excludes T&D costs, which would be affected by electrification and DSM. Please consider providing a rough estimate of the potential sensitivity of T&D costs to these scenarios in the IRP report even if estimates cannot be provided by scenario.	The Avoided T&D cost estimates, being developed in parallel to the IRP with the DSM Advisory Group, will provide some insight into potential costs of electrification, particularly in constrained areas that are already experiencing load growth.
Capital cost	CA-06 Consumer Advocate	Request more detail on how the “revenue requirement profiles” for the “supply-side options that represent a capital investment” are computed in the objective function of the long-term Plexos model (2020 IRP: Financial Assumptions, March 11, 2020). Do you use annual, nominally-levelized or real-levelized revenue requirements, and how are income taxes are reflected in the revenue requirements computation, in addition to book depreciation and return (which we assume is included at the 6.62% pre-tax rate). A display of the assumed revenue requirements from a combustion turbine, a wind installation and the reliability tie would be useful to ensure that we understand what you are doing.	NS Power has provided this information in prior materials releases however, will reach out to the CA to confirm if additional explanation is desired.

Scenarios	CA-07 Consumer Advocate	We suggest four changes to the scenarios (or sensitivities) that will be run for the IRP. Natural gas price capacity plan sensitivity: The most recent FAM report suggests that there has been a shift from coal to gas driven by changes in fuel price. We suggest that NS Power should develop a capacity expansion plan that explores what level (or duration) of fuel price changes might trigger an economic decision to implement early coal retirements or otherwise affect the capacity build. No-transmission sensitivity: Since the reliability tie and regional interconnection were selected in every scenario (except the comparator case), we suggest that there should be a capacity plan with steam retirements but without the major transmission options, to identify what resources would be selected. It may be appropriate to study the interactions of the natural gas price and transmission sensitivities with the wind analysis discussed below. We observed that early coal retirements occurred in the net zero 2050 scenarios with distributed resources or low wind costs, indicating that coal plants are at least somewhat sensitive to low-cost energy. Hydro avoided costs sensitivity: We understand that there will be a specific “without Mersey” case. In addition, we suggest that NS Power develop three additional expansion plans in order to develop avoided costs for Wreck Cove and the two small hydro system groups. These avoided costs would them be used in future economic assessment model (EAM) runs during capital project filings. This could be completed after all other modeling is done, as we do not	NS Power has now conducted a High import/High Gas price sensitivity on scenario 2.1C. Since these resources were selected widely across key scenarios, NS Power agreed it was important to understand the robustness of this resource selection. These results have been released with the Draft Report. The Regional Integration option (i.e. large firm imports via new transmission) was only enabled as candidate resources in a subset of scenarios (X.X.C). The Current Landscape Scenarios (X.X.A) did not have access to large firm imports. All scenarios had access to the Reliability Tie as a candidate resource to enable wind integration. Based on stakeholder feedback, NS Power did undertake a sensitivity to test the value of this interconnection, by specifically excluding this interconnection from the candidate resources. Sensitivity 2.0A Import-2 examines this scenario. NS Power did undertake a No Mersey Plexos sensitivity, please see 2.1C.Mersey. NS Power will consider the suggested Hydro avoided cost analysis upon completion of the IRP.

Category	Comment #	Comment	NS Power Response
		believe these model runs are likely to have any other significant role in the final IRP analysis.	
Electrification/ HalifACT	CA-08 Consumer Advocate	While the scenarios are mostly consistent with HalifACT, With respect to the electrification goals in HalifACT 2050, it does not appear that NS Power's electrification scenarios in the load forecast are as ambitious as the HRM's goals. The limited description of the high-electrification scenario in the IRP make it difficult to determine how closely the two plans track. But the divergence in the electrification assumptions appears to occur mostly after 2030, so the high-electrification scenarios are likely to be adequate to develop an action plan consistent with HRM's electrification goals. Even a fairly aggressive program (whether sponsored by HRM, NS Power or some other entity) is unlikely to substantially exceed the levels of EVs and building electrification in the high electrification scenario before NSP's next IRP, which we assume will be completed around 2025. At that time, if vehicle and building electrification were progressing consistent with HRM's goals, then NS Power would need to adopt significantly higher assumptions for building electrification.	NS Power agrees with this interpretation.

Category	Comment #	Comment	NS Power Response
Wind costs	CA-09 Consumer Advocate	NS Power's 2019 [wind] capital cost of $2,100 per kW is outside the cost envelope suggested by Lazard and others have commented it is higher than market. NS Power's response includes a single scenario in which the 2019 capital cost is reduced from $2,100 per kW to $1,500 per kW. This scenario results in a significantly higher near-term wind capacity procurement (118 MW in 2.1C.S2 vs 57 MW in 2.1C). Recommendation: Compare assumptions to the contract prices in New Brunswick if possible. If New Brunswick costs are lower than NS Power's assumption, then either the model cost assumption should be revised, or NS Power should explain how Nova Scotia conditions would differ from New Brunswick conditions and justify the higher cost assumption.	As detailed in the Supply Options Study, completed during the Pre-IRP phase, NS Power's wind cost assumptions were informed by market indices such as the NREL ATB and WECC surveys, and by looking at regional data such as NB Power IRP assumptions. NS Power has proposed an Action Plan item to solicit Nova Scotia market based information for wind.

Category	Comment #	Comment	NS Power Response
Wind integration	CA-10 Consumer Advocate	NS Power caps the wind build at 100 MW (700 MW total installed) unless either reliability tie or a battery + synchronous condenser capital investment (referred to as domestic integration) is made to support reliability. The PSC study found that during periods of high wind and high imports, the loss of an intertie could cause stability issues. There are two alternative operational responses to accommodate additional wind. First, under hourly conditions of high wind and high imports without the reliability tie, wind generation could be capped at 700 MW. Second, under conditions of high wind, a minimum conventional (thermal or hydro) online capacity requirement could be established, which would both provide additional local inertia and reduce imports, avoiding the high wind/high import combination.	IRP runs consistently show economic utilization of non-firm imports in the early years of the planning horizon which indicate a significant percentage of hours could be classified as high imports. However, NS Power has established in its Action Plan to further study system stability and associated constraints as it pertains to wind or other invertor based renewable energy integration, particularly under normal or "non-stressed" conditions as was recommended in conversations with stakeholders.

Category	Comment #	Comment	NS Power Response
Inertia	CA-11 Consumer Advocate	NSP should conduct capacity expansion plan modeling with no inertia constraint and/or with a 1500MW-s inertia constraint to show the sensitivity to the inertia constraint. The model results are very sensitive to the cost of wind. The cost of adding wind above the 700-MW threshold is greatly affected by the cost of the reliability tie; the need and timing of the tie depend entirely on NS Power's application of the PSC report's reliability findings. We recommend that NS Power provide results in its final report that apply alternative inertia constraints. Assuming the differences are significant, further study after the final IRP report is issued could clarify the inertia constraint and other relevant reliability considerations so that NS Power can determine the appropriate level of wind development that may be supported prior to investing in the reliability tie.	NS Power has accepted these recommendations and included additional sensitivities in the Final Portfolio Study. In particular, 2.1C.Wind-3 was modeled with a lower inertia constraint (2200MW.sec) and 2.1C.Wind-4 was modeled as a boundary case with no inertia constraint modeled, as well as no integration requirements for wind energy (i.e. Reliability Tie or Domestic Integration). As recommended, NS Power has included further refinement of these constraints, including additional studies of normal operating conditions, in its IRP Action Plan.

Category	Comment #	Comment	NS Power Response
ELCC	CA-12 Consumer Advocate	The E3 Capacity Value study indicates that the wind ELCC drops from 38% at near-zero capacity to 19% at NSP's current wind capacity (E3 Capacity Value Study, p. 58). We agree with the E3 report that the capacity credit for wind and other renewable resources should decrease as additional wind is installed. This strongly implies that existing resources should receive a higher credit that incremental resources. However, the current IRP assumptions appear to give an ELCC value of 19% for both installed and incremental wind capacity. With respect to the installed wind capacity, we believe that the ELCC should be higher for three reasons. • As noted above, the wind resource modeled by E3 performs far worse during peak hours than indicated by the data provided by NS Power. • Our calculations, following the LBNL method (see footnote), suggest existing resources should have an ELCC of about 25%, as described below. • E3's calculation of a 19% ELCC at current wind levels may be a marginal value (reflecting incremental system resources), not an average value (reflecting existing system resources).	NS Power provides a 19% capacity value for the existing approx. 600MW of wind, as derived in the E3 Capacity Value Study. NS Power's IRP modeling assumption for capacity value from incremental wind is to model it linearly at 10%; this is a linearization designed to capture the range of 11% marginal capacity value at 600MW total installed capacity to 9% at 1000MW total capacity, as shown in the IRP Assumptions on slide 52.

Category	Comment #	Comment	NS Power Response
Wind integration	CA-13 Consumer Advocate	NS Power may model these operational constraints (curtailments or minimum commitment requirements) in its planning models, in which case the model could directly compare the cost of the operational constraints to the reliability tie and to the benefit of higher wind capacity. Alternatively, NS Power may need to exogenously estimate the amount of curtailment or uneconomic commitment to deal with extreme conditions, and the cost of those actions, and use that cost in lieu of the reliability-tie cost. If the model were allowed to build additional wind with operational constraints, it might well choose to add that wind earlier than 2029 and defer the reliability tie until later in the study period. Under the assumption that operational restraints are used, and low wind costs are available in the market, at what dates does the model suggest building more wind than the operational constraints can accommodate, requiring the reliability tie? What additional reliability and operational studies are needed to verify the performance and cost-effectiveness of using operational constraints to address the high wind/high import issue? c) If wind prices are attractive enough to go beyond the wind capacity that can be facilitated with the operational constraints, how long a lead time would NS Power require to make a build or defer decision for the reliability tie?	NS Power has proposed an IRP Action Plan item related to continued refinement of synchronized inertia requirements, including examining dynamic modeling options, for post-IRP work. The assumptions have been developed using the PSC Stability Study from the Pre-IRP work as the basis for assumptions. The i) Reliability Tie and ii) Local Mitigation options were identified as enablers of larger increments of wind. NS Power has proposed an Action Plan item to solicit Nova Scotia market based information for wind, which will inform future wind procurement. Future procurement for the Reliability tieline, with the primary objective of integrating more domestic wind, would assess a broader array of potential integration alternatives.

Category	Comment #	Comment	NS Power Response
ELCC	CA-14 Consumer Advocate	ELCC of incremental wind After taking into consideration the capacity credit associated with wind, the capacity factor for wind in the top 1.1% of peak hours drops from 61.3% to 19.7% in the top 1.1% of net peak hours. In the 4-year dataset provided by NS Power, the top 1.1% hours are those hours with load of 1,840 MW or with a net load of 1,697 MW. This indicates that the 595 MW of wind reduced load by about 143 MW, or a 25% capacity credit. Thus, while our analysis supports the use of a 19% ELCC for incremental resources, we find that the existing wind resources should have a UCAP Firm Capacity of 143 MW rather than 113 MW.	See response to CA-12 above. NS Power has discussed with the CA its use of the ELCC analysis to determine the capacity value of both new and existing wind generation on the Nova Scotia system. ELCC analysis looks at the contribution of wind to firm capacity on an 8760 basis rather than just looking at a small number few peak hours.
Wind integration	CA-15 Consumer Advocate	Since the IRP process does not include an opportunity to further investigate the cost of wind resource development or further study the practicality of operational constraints, it is essential that the final modeling scenarios appropriately examine these questions to provide the Board with the context it needs to evaluate the need for and potential scheduling of the reliability tie.	NS Power has expanded the sensitivity analysis completed as part of the Final Portfolio Study per the recommendations of the CA and other IRP Participants; please see responses to CA-07, CA-09, and CA-11 for more information.

Category	Comment #	Comment	NS Power Response
DSM impacts	CA-16 Consumer Advocate	The 2.0A pair has a NPVRR difference of $337m and the 2.1C pair has a difference of $544m. Why is the difference so substantial based on the electrification level? Why is the mid DSM incremental cost more than the supply resources it replaces? Would the avoided T&D costs associated with a higher level of DSM potentially offset the cost difference? The model is making changes that seem counter-intuitive when shifting from base to mid DSM. The shift from base to mid DSM in case 2.1C (vs S1) results in an early build of an NGCC unit, reducing gas peaker capacity, and reducing firm imports. Is there something about the way firm imports are characterized that needs to be reconsidered? Why is the model suggesting that it is economic to build a unit that produces more energy when there is less energy to serve?	The Final Portfolio Study results show 2.0A difference of $360M and 2.1C difference of $327M. A number of enhancements were made to the model since the initial set of runs to fine tune the results, including incorporating PLEXOS MT/ST hourly production costs into the scenario NPVs. The Mid DSM costs are approximately double the Base DSM costs but provide only a 10-15% increase in energy and demand savings. Given the small increase in demand savings with Mid DSM it is unlikely the cost difference would be offset. The latest results show an additional 147 MW of NG steam retirements in 2.1C Mid DSM (in 2029) compared to the 2.1C Base DSM. The 145 MW NGCC is built one year earlier in the Mid DSM case due to the additional retirement. Gas peaker capacity is about the same, firm import is 5 years earlier in the Mid DSM case due to the additional retirement.

Category	Comment #	Comment	NS Power Response
ELCC	CA-17 Consumer Advocate	ELCC of Wreck Cove and Mersey Can NS Power explain why Wreck Cove operates so little in high-load hours? Does NS Power normally hold a large portion of Wreck Cove in reserve at peak? Does Wreck Cove have available energy resources to support a 95% ELCC value, given the long evening winter peaks? While the Mersey units are dispatched more reliably than Wreck Cove in high-load hours, its dispatch does not match the UCAP/ELCC that NS Power claims for this system. Its capacity factor also declines from the winter, to peak days, and to net peak hours. Does Mersey have enough flexibility in dispatch to be held in reserve at peak, or does the system simply produce less energy in the hours that tend to have high loads?	Wreck Cove is an energy-limited peaking plant and an important source of ancillary grid services such as reserve. When modeled in the capacity study in the pre-IRP phase, Wreck Cove was modeled as a dispatch limited resource with a daily energy budget equivalent that varied by month. The ELCC analysis completed under these assumptions supported the 95% ELCC rating for the Wreck Cove facility. Mersey was also examined in the pre-IRP capacity study and determined to have an ELCC of 95% via that model; the system was modeled as having sufficient pondage to cover any duration of peak event due to storage at Lake Rossignol.
Regional Integration	CA-18 Consumer Advocate	The regional interconnection is built in 2030 if the more aggressive climate policy is selected, except in the mid-electrification case with high distributed resources. Otherwise, it is built in 2038– 2045. Run a sensitivity to one of the 2040 or 2045 build cases that forces the build in 2030. It would be interesting to see if the cost difference is significant. Building or postponing this upgrade well beyond 2030 is a significant near-term decision point, and NS Power should determine whether it should move forward with planning on this project, since it would require cooperation with New Brunswick and possibly Quebec.	NS Power will refine the timing of the Regional Interconnection transmission builds as part of the development of a Regional Integration Strategy as identified in the IRP Action Plan. The proposed discussions with neighbouring jurisdictions will inform this work as well.

Category	Comment #	Comment	NS Power Response
Storage	CA-19 Consumer Advocate	It appears that in most cases with near-term wind procurement over 100 MW, there is a relatively large amount of 4 hr battery storage selected as well. If that is correct, the final plan should recommend that wind procurement should generally proceed in combination with a storage procurement.	The Draft Findings provide that batteries can enable wind integration while providing firm capacity and energy storage; however, their ability to substitute for firm capacity resources is limited by its relatively short duration. Up to 120MW of storage by 2045 is selected in the portfolios with deployments of 30-60MW by 2025 in many plans. The draft Roadmap provides that NS Power will track the installed costs of energy storage and will solicit Nova Scotia market-based information which would inform this as needed.

Category	Comment #	Comment	NS Power Response
Combined Cycle Gas	CA-20 Consumer Advocate	It is surprising to see a combined cycle built so late in the 2.2A and 2.2C cases, as well as being built in the 3.1 and 3.2 cases. We are concerned because it is our understanding that the objective function of the model includes costs and benefits at 2045 operational levels through 2070 via end effects. Given the 2050 climate targets assumed in these cases, but not really represented in the model, we believe there may need to be modifications to the model to ensure that combined cycle plants are financially viable without an assumption that the plants will operate beyond 2050. Ideally, NS Power would simply limit the useful life of a combined cycle to 2050. However, there are at least two reasons why this simple approach may not be practical in the current modeling environment. First, this may result in creating a unique resource for each year in the model, which may result in too much model complexity. Second, the end effects associated with a gas plant retirement in 2050 may result in the model considering costs and benefits of the gas plant in 2045 continuing through 2070 – which is clearly inconsistent with the net zero carbon scenarios. NS Power should identify a workable approach that allows the benefits and costs of a combined cycle plant to be reflected in a way that approximates retirement by 2050. As discussed above, it may make sense to limit or eliminate end effects calculations as part of the objective function. If that was done, then the number of resource options could be limited by offering units with 25, 20, and 15-year lifetimes, with no combined cycle plants built after 2039.	NS Power agrees that the treatment of late period builds is challenging and notes that there is considerable uncertainty associated with these builds, including what offsets may be available under a net-zero compliance approach and whether low or zero emission fuels or fuel blends may be available (e.g. hydrogen, biofuels). NS Power has not limited the model from building these late resources but believes they do not have a significant influence on the near-term resource plan (5-10 years) based on the timing of other resource additions (e.g. regional integration capacity) and late period unit retirements.

Category	Comment #	Comment	NS Power Response
Wind	CanREA-01 Canadian Renewable Energy Association	Recommendation: more analysis be conducted to consider how these specific capabilities of wind energy, coupled with other technologies like storage, will in fact, enable more, cost effective wind energy to be integrated to the grid without significantly more infrastructure investment. With the implementation of an obligation on new and existing wind projects to provide FFR, it may be economic and feasible to add additional wind generation well beyond 100 MW without major infrastructure investment.	NS Power has provided two additional model runs as part of the Sept 2 modeling results release; one models a lower system inertia requirement of 2200MW.sec and one has no inertia constraint or wind integration requirements. NS Power has also proposed an IRP Action Plan item related to continued refinement of synchronized inertia requirements, including examining dynamic modeling options, for post-IRP work. Based on stakeholder feedback, in the Final Portfolio Study NS Power allowed new wind resources to contribute to the system ramp down reserves when online, reflecting potential enhanced contributions to ancillary services from new wind resources.

Category	Comment #	Comment	NS Power Response
Wind	CanREA-02 Canadian Renewable Energy Association	We understand that the operability analysis is likely to be test scenarios that were evaluated in PLEXOS to ensure that they do not adversely affect reliability. CanREA encourages NSPI to ensure that these analyses consider at minimum the impact of new frequency response provision requirements for non-synchronous/inverter-based resources in terms of enabling additional wind generation in Nova Scotia in the near term without major infrastructure investments. Forecasted near-term reductions in both the levelized cost of wind generation, and competitive system costs of inverter-based generating resources and energy storage as compared to a synchronous generation-based system, suggest that increased volumes of these resources could reduce costs for Nova Scotia consumers while advancing the Province's environmental goals.	The Operability Assessment completed as part of the IRP is not able to reflect the type of dynamic/transient analysis that would capture new wind contributions to Fast Frequency Response services. NS Power has identified this area of additional work as a proposed post-IRP Action Plan item.

Analysis	CanREA-03 Canadian Renewable Energy Association	Key unexplained results that are surprising and appear counter-intuitive are the high levels of gas turbine build and relatively low levels of battery build How were ancillary service provision by various resources modeled? • Does this modeling reflect the underlying higher performance of ancillary service provision that batteries and other non-synchronous/inverter-based resources can achieve relative to conventional resources including thermal generation? Experience in other electricity markets (e.g., PJM etc.) indicates that the quality of AGC service provided by batteries is such that it can reduce the underlying requirements for these resources to provide this service, reducing costs to customers.	Plexos LT module optimizes resource plans constrained by all ancillary services (reserve) constraints, co-optimized with unit commitment and dispatch. The suite of the new resources including wind and batteries are contributing to certain modeled ancillary services. Namely, wind resources are part of the regulation lower service. Batteries contribute to all types of reserve including regulation (raise and lower), spinning and non-spinning. The quality of AGC service provision is too granular to be modeled in a capacity expansion model. NS Power notes that the ELCC of battery storage declines relatively quickly with installed capacity on the Nova Scotia system, in part due to the more variable nature of the wind resource (e.g. multi-day periods of either high or low wind generation) that the batteries are supporting as compared with a more predictable daily solar profile.
		Does the end effects analysis adequately consider additional costs of fossil-based resources relative to renewable resources recognizing that carbon constraints and costs associated with exceeding these are likely to become increasingly significant? • Does the end effects analysis adequately reflect future operating constraints on fossil-based resources? • Does the end effects analysis adequately reflect increasingly stringent carbon constraints imposed after fossil investments are made • How was the loss of flexibility or these cost penalties considered?	The End Effects treatment assumes the 2045 resource portfolio has an infinite reinvestment horizon. It does not consider alternative environmental compliance requirements beyond this year. NS Power notes that the capacity factors of the combustion turbine resources added for capacity are very low (less than 10% per year in the vast majority of cases, and in many years less than 5%) and has added monitoring low and zero carbon fuel development (e.g. Hydrogen, Biofuels) to its IRP Roadmap
		Were the potential benefits of hybrid projects (wind/energy storage or solar/energy storage with storage embedded behind the meter) adequately considered?	The IRP did not model hybrid projects for storage behind the meter but provided both storage and renewable generation options separately

Category	Comment #	Comment	NS Power Response
		• hybrid projects can provide required ancillary services (e.g., frequency response services) at lower cost by avoiding opportunity costs associated with the provision of some frequency response services as well as provide a desired capacity resource at a relatively low effective cost.	

Category	Comment #	Comment	NS Power Response
DSM sensitivities	E1-01 Efficiency One	Model additional sensitivities with respect to differing DSM cases. Modelling additional sensitivities is required to adequately test DSM's impact in the context of the various 2020 IRP scenarios. The requested sensitivities in each scenario are detailed on pages 3-4 of this memo. Two sensitivities were modeled . These runs do not provide a full set of expected sensitivities. Additional sensitivities will provide further and necessary insight on the appropriate DSM trajectory for Nova Scotia. At minimum, results should be provided from: Completion of a DSM sensitivity examining Mid-DSM levels within case 2.0C (Net-Zero, Reference Electrification, Regional Integration) A DSM sensitivity examining Mid-DSM levels within case 3.lC (Accelerated Net- Zero, Mid-Electrification, Regional Integration) A DSM sensitivity examining Mid-DSM levels within case 3.2C (Accelerated Net- Zero, High-Electrification, Regional Integration) A DSM sensitivity examining Mid-DSM levels within case 2.2C (Net-Zero, High- Electrification, Regional Integration) In addition, should the distributed energy versions (X.XB) of the above remain in consideration following further analysis, they should also receive similar sensitivity treatment as outlined in the bulleted list above.	NS Power completed the following additional DSM sensitivities and released them with its updated modeling results release on September 2; this list of DSM sensitivities was developed in collaboration with E1. 2.0A.DSM-1 — Low Electrification / Mid DSM 2.1C.DSM-2 — Mid Electrification / Mid DSM 2.2C.DSM-3 — High Electrification / Mid DSM 2.0C.DSM-4 — Low Electrification / Low DSM 2.0C.DSM-5 — Low Electrification / Mid DSM 2.0C.DSM-6 — Low Electrification / Max DSM 3.1C.DSM-7 — Mid Electrification / Mid DSM / 2030 Coal Retirement

Category	Comment #	Comment	NS Power Response
DSM sensitivities	E1-02 Efficiency One	2. Confirmation that full resource re-optimization is occurring for all sensitivity runs, including re-optimization of the planning reserve margin to levels that satisfy, but do not greatly exceed NERC requirements.	Confirmed.

Category	Comment #	Comment	NS Power Response
Distributed Resources	E1-03 Efficiency One	3. Continue to refine the cost estimates for Distributed Resources, as they currently span a wide uncertainty range. Existing and planned data, including costs, from Smart Grid Atlantic and NS Power's Smart Grid project may be useful in doing so. Basic information has been provided relating to the envisioned costs for renewable DERs - described as "$1.6-2.5B" on an NPV basis. These costs have not been directly included in the NPV revenue requirement of any modelling scenario. Continue to refine, and use data from Smart Grid Atlantic and NS Power's Smart Grid project. Current solar PV offerings in Nova Scotia do not leverage ratepayer investment, and no such programs have been planned to date. Given that there already exist three differing and incomparable sets of revenue requirements within the IRP (reference, mid and high levels of electrification), having three incomparable cases through DER levels is cumbersome, and will likely stifle clear determinations about effective resource strategies. 4. With respect to Distributed Resources cases, define the portion of the NPV revenue requirement that will be ratepayer-funded, and include it within NPV revenue requirements.	NS Power has provided a range of cost estimates sufficient for understanding the directional impact of these costs when added to the NPV calculations. Continued refining of cost estimates for DERs is beyond the scope of the IRP exercise. Inclusion of DER scenarios was determined through consultation with stakeholders on the Analysis Plan and Scenarios (in February 2020). Based on feedback respecting challenges associated with comparing scenarios reflecting differing load levels due to electrification and consideration of DER scenarios, NS Power has provided a rate analysis with the draft Findings release to provide a better comparison across plans to understand implications for ratepayers. For the purposes of IRP analysis, the costs of investment in DERs is outside of the utility model.

Category	Comment #	Comment	NS Power Response
DSM costs	E1-04 Efficiency One	Levelization of DSM Costs 5. Re-run DSM scenarios with an amortized capital cost stream, similar to the treatment for supply-side resources. Presently, DSM is being modelled within the IRP on an expensed basis, as opposed to an amortized basis. Based on the treatment of supply-side resources on an amortized basis, the DSM scenarios should be re-run with this similar treatment. El can assist in this by providing an amortized cost stream which reflects the amortization across the average measure life of each year's potential DSM activities (this cost stream would extend into the end effects period). This will provide more accurate information regarding the true competitiveness of DSM, as opposed to a result which may include artifacts from the differing financial treatment of DSM.	Upon discussion with E1, E1 advised that it was withdrawing this request. The modeling approach is aligned with the current treatment of DSM costs as an expense.

Category	Comment #	Comment	NS Power Response
Demand Response	E1-05 Efficiency One	6. Allow the introduction of Demand Response (DR) in 2021, 2025, 2030, and 2035. This would provide a better balance and consistency in model runs, and more accurately estimate the value of DR in Nova Scotia. 7. Re-run all scenarios allowing DR to economically compete against new and existing natural gas peaking infrastructure Additionally, please clarify on the following points relating to how DR was modelled: In scenarios where DR is selected, it appears that 82MW of capacity is in place in year 1 (2030). Does the model assume that level of DR remains in place until 2045 with no changes in capacity? What is the DR profile for the remaining years? Is there a ramp-up built into the DR assumptions as is the case with the 2019 DSM Potential Study? Was DR available to the model in place of selecting the build-out of ~37MW capacity of new gas combustion turbines and reciprocating units in 2021?	In the Final Portfolio Study NS Power offered the DR resources in 2021/2025/2030. In all scenarios, DR was selected economically prior to 2035. The DR Profiles reflect the ramp up in nameplate capacity and cost profile, as provided by E1 for Low/Base/High DR cases. The DR programing provided by E1 covers the period 2021-2045. For all entry points, there is DR capacity savings in 2045, as applicable to the entry year (e.g. if selected in 2021, the 2045 capacity savings would be equal to the 2045 DR capacity savings provided by E1. If selected at another entry point, the capacity savings is shifted later accordingly). Yes, DR was modeled as a supply side resource available along with natural gas units and other resources in this round of modeling. In the Final Portfolio Study, DR was available for selection in 2021, however, gas units were not available to the model until 2023. The PRM constraint was not enforced in 2021 or 2022 in the Final Portfolio Study in order to better manage this model behaviour.

Category	Comment #	Comment	NS Power Response
Plexos Information	E1-06 Efficiency One	Provide quantitative inputs and outputs from Plexos in tabular format, as initially requested on May 12, 2020 with a priority for the Comparator cases l.0A and l.0C. To note, requests for release of data have been addressed by NS Power through an alternative arrangement for a technical session with El and its consultant, where PLEXOS model parameters and data can be examined.	As noted, E1 considers this request to have been addressed by NS Power through an alternative arrangement for a technical session with E1 and its consultant where Plexos model parameters and data were examined in detail.
	E1-07 Efficiency One	Within the written deliverables (Draft Findings, Roadmap & Action Plan) to be released (per the Terms of Reference), provide findings for each evaluation category for each candidate resource plan considered. This will allow stakeholders to better follow the more qualitative aspects of the evaluation process. When selection decisions are being made regarding specific candidate resource plans, or groups of similar plans, justification should be provided on the basis of evaluation criteria, and the relative importance of each criteria in making such a determination.	NS Power has provided its draft Findings, Roadmap & Action Plan which are based on the metrics that have been established for the process.

Category	Comment #	Comment	NS Power Response
Capacity Value of Non-Firm Imports	E1-08 Efficiency One	Clarify any ongoing modelling impacts associated with the use of non-firm imports in RESOLVE. Confirm that the PLEXOS LT runs do not count any non- firm imports as capacity. Provide additional information and support regarding firm import assumptions to allow stakeholders to assess the reasonableness of these assumptions. Clarify which candidate resource plans depend on the addition of 450 MW of firm imports from Quebec, or portions of this capacity if Plexos did not take the entire volume in any given scenario. Include a sensitivity analysis run that limits market imports (both firm and non- firm) to 110% of recent historical averages, excluding the Maritime Link NS block. This inclusion would provide the benefit of a view with limited expansion of market opportunities, which El believes warrants consideration.	There are no ongoing modeling impacts. Confirmed. All information respecting firm import assumptions were provided with the Final Assumptions release in March. Stakeholders were provided the opportunity to comment on Assumptions before they were finalized. Detailed information on import selection, including price and quantities, that can be tied to a single counterparty is not being provided for competitive reasons. Sufficient information has been provided in a manner that protects commercially sensitive details for the benefit of customers. NS Power modeled a sensitivity that limits non firm imports available to the model; please see 2.1C.Import-1.

Category	Comment #	Comment	NS Power Response
Natural Gas	E1-09 Efficiency One	A proxy for new gas supply should also include a sensitivity relating to the Algonquin City Gates Hub (AGT) as the commodity price for new winter (and summer) natural gas capacity, with the inclusion of energy cost and tolls reflecting transport from AGT to Tufts Cove, as it would address some of the uncertainties associated with the current approach of acquiring gas and transportation from Alberta (AECO), Dawn or LNG via Amsterdam (TTF). Sensitivity analyses that explores the constrained availability of natural gas for the NS electricity system should be included, at least in terms of incremental capacity additions beyond 20,000 MMBtu per day. Put another way, constrain the model to only allow for consumption of 20,000MMBtu per day, thus allowing the model to economically select other resources other than natural gas beyond the currently contracted firm supply. 3. Gas price sensitivities can then appropriately explore higher or lower pricing scenarios that impact future capacity additions to the system, and differing limits on the availability of gas. These fundamental questions regarding natural gas pricing and availability must be answered in the context of the IRP prior to it being finalized if the IRP results are to show the degree of sensitivity to commodity costs. They will fundamentally affect pricing and the selection of resources, which will not be reflected in an after-the-fact analysis.	When developing a plan for assumptions that would require a firm gas supply, NS Power's analysis indicated that volumes would not be available from AGT that could potentially be required. AGT is treated as opportunistic gas, as there is limited firm transportation available. Further, because AGT experiences more severe winter prices than AECO, and NS Power is a winter peaking utility, it was deemed that the supply source modeled in the IRP is likely more economic. As per the Final Assumptions document, gas supply options were developed on the basis of new natural gas units economically selecting firm access to a gas supply to operate at significant capacity factors. NS Power does not feel that the LNG Winter-Dawn summer pricing alternative would be constrained in this regard. The supply path from AECO (Path 3) considered transportation upgrades to firmly supply Nova Scotia (and a fixed cost adder applied to gas units in the model for this option). A High Natural Gas / High Import Price sensitivity was modeled based on stakeholder feedback and released with the Draft Report.

Category	Comment #	Comment	NS Power Response
Scenarios - GHG emissions	EAC-01 Ecology Action Centre	Model scenarios that achieve zero GHG emissions The study is inconsistent with GHG trajectories needed to align with international, federal, provincial, and local emissions reductions plans. No zero emission scenarios are studied, although the study mentions that mid- and high-electrification scenarios follow SDGA 2050 end points, and there are delayed zero emission targets; perhaps never achieving zero emissions will limit the opportunities for other sectors to rapidly decarbonize. Model zero-emission cases for 2050, 2045 and 2035. A zero emissions study enables the model to compare the costs of adding carbon sequestration to these [natural gas] generators against the costs of increased clean imports. It is not clear from the scenarios studied that replacement of coal thermal plants with natural gas infrastructure is the lowest long-term pathway to a zero emission state. Modelling accelerated zero emission timelines may well reveal lower long-term cost solutions. Accelerated net zero timelines can and should analyze multiple energy mixes.	The GHG scenarios being modeled incorporate significant emissions reductions, from ~5MT at the beginning of the study period to 1.4-0.5MT in 2045 under the 2.x and 3.X emissions curves. This requirement includes a mandatory phaseout of all coal generation within the planning horizon. The Accelerated Net Zero 2045 case (0.5MT in 2045) represents NS Power's view of a path to absolute zero in 2050.

Category	Comment #	Comment	NS Power Response
Scenarios	EAC-02 Ecology Action Centre	The study restricts the model's ability to add firm imports and as such biases the result towards gas turbine construction, continued natural gas purchases and GHG emissions from both direct combustion and upstream fugitive methane emissions (which are not currently accounted for under this process). Long decarbonization trajectories endorse the replacement of coal generation with natural gas resources and it is not clear if these generators will be cost effective when utility emissions are regulated to zero. Faster trajectories to zero electric utility emissions may be more cost effective over the study period and the related end-effects time frame.	In the Regional Integration scenarios, the model is able to select both limited quantities of firm import capacity and energy over existing transmission assets as well as more significant quantities of capacity and energy which require transmission build-out. In addition, non-firm energy imports are available to the model over existing and new transmission infrastructure. This provides the model with the ability to source a significant portion of required energy and capacity from outside Nova Scotia, if economic. Significantly larger quantities of firm imports than currently modeled could represent a reliability and self sufficiency challenge, as NS Power must be able to accommodate the loss of its largest generator or firm import, and so are not considered in this IRP.

Category	Comment #	Comment	NS Power Response
Natural gas and Diesel generators	EAC-03 Ecology Action Centre	Report the detailed operational profiles of natural gas and diesel generation assets (number of operations per year, their durations and power and energy associated with each unit). This data will be useful in using these model choices as proxies for identifying cost effective alternate generation or storage solutions in the future. These may include long duration battery storage or tidal power, among others, as technologies mature. One specific example would be the recent announcement of a 150 hour duration battery demonstration by Form Energy and Great River Energy in Minnesota.	NS Power continues to provide generation results from unit classes as part of modeling releases, e.g. total generation by year from both Natural Gas and Diesel combustion turbines. Samples of natural gas and diesel combustion turbine outputs were provided as part of the Operating NS Power will continue to monitor developments in storage technology, including long duration storage solutions and its economic competitiveness vis-à-vis other primarily capacity-oriented resources.
Timeline	EAC-04 Ecology Action Centre	Recommend an extension for more stakeholder interaction, to November 30, 2020.	NS Power and the Board have adjusted the final deliverable date to accommodate additional analysis and stakeholder interaction. NS Power looks forward to continued stakeholder engagement over the reminder of the IRP process.
Transmission	EAC-05 Ecology Action Centre	Ensure that the model's portfolio of assets always includes the ability to add an additional transmission line through New Brunswick to Quebec as identified in the IRP assumptions set.	Confirmed that this firm import option is available in all Regional Integration scenarios ("C" models).

Category	Comment #	Comment	NS Power Response
Scenarios – net zero	EAC-06 Ecology Action Centre	No carbon credit purchase costs are included to bring the net zero cases to net zero. As such, these cases should be labeled Near-Zero rather than Net-Zero. Negative emission curves are possible but not addressed. The scenarios that proceed to net zero do so outside the planning period. Do the trailing end effect costs include carbon sequestration from the operational gas plants at the end of the study period? Because no zero emissions case within the study period has been considered and all near zero cases build combined cycle gas to work with intermittent wind resources, these predictable costs are not identified. It is plausible that a zero emissions limit at 2050, 2045 or 2035 would choose interconnection over generation if it had access within the model to more regional interconnection. It may be that greatly reduced generation is built and that zero emissions are achieved faster for limited additional expense to the utility and avoided rate base costs to the ratepayer. The last thing this process should plan for is a new life cycle of generation that will require expensive upgrades or premature retirement. Only a zero emission scenario can fully determine if this is truly cost effective.	The trailing end effects costs do not include the cost of carbon sequestration. An earlier absolute zero target would require a fulsome change in assumptions and significantly more study. As suggested, a reliance on imports for the majority of Nova Scotia's peak demand requirements and the associated impacts on affordability, reliability and self sufficiently would need to be thoroughly studies to provide meaningful modeling inputs. NS Power has focused the efforts of this IRP on modeling a deep decarbonization of the electricity system, representing an 87-95% reduction from 2005 levels, while simultaneously supporting decarbonization of other sectors of the economy via electrification. NS Power believes these scenarios will continue to be of interest in future planning studies. In the majority of scenarios, high utilization combined cycle gas units are not built until late in the planning horizon. The economics of these units could change in the interim. Such material changes to the current IRP assumptions will be monitored in NS Power's IRP Evergreen process. NS Power has also proposed examining low and zero carbon fuel blends (e.g. hydrogen, biofuels) as part of it's IRP Action Plan and Roadmap.

Category	Comment #	Comment	NS Power Response
Electrification benefits	EAC-07 Ecology Action Centre	The costs to the ratepayer are not fully comparable between scenarios. High electrification cases presume that consumers are replacing fossil fuel costs for heating and transport with electrical costs and there is substantial potential that this transition will provide significant financial benefit to consumers, and health benefits to the province, which are not captured in the scenarios. This includes transportation and building heating and electrification. While the E3 Pathways report contemplates electrification of heating systems, it does not account for improved building quality beginning in 2030 from new construction, nor is there an assumption around the rate at which older building stock may be renovated, and more efficient buildings are more capable of demand response as well, so the load in high electrification scenarios may be overstated.	NS Power agrees that there are economic costs and benefits associated with electrification that are not included in the IRP analysis. NS Power is interested to continue to explore these as part of the Electrification Strategy that has been proposed in the IRP Action Plan. NS Power has provided a rate impact analysis with its draft Findings release to enable better comparison across differing load scenarios.

Import and Natural Gas	EAC-08 Ecology Action Centre	Import and Natural Gas Trade-offs: Scenarios that modeled regional integration indicate that the Reliability Tie (345 kV Onslow - Salisbury) and the Regional Interconnection (345 kV Salisbury to Coleson Cove) are selected early when seeking solutions to declining GHG limits. The March 11, 2020 IRP Assumptions listed a third interconnection (Salisbury - Quebec HVDC) and it is not clear that this was an active option in all of the modeled scenarios or just the regional integration scenarios. If it were available, it is not clear that, if presented with a zero emissions case in the study window, the model might well choose it over gas generation with carbon sequestration. In addition, there is a risk that continued natural gas purchases will ultimately carry a higher carbon emissions factor due to upstream fugitive methane emissions. While not currently accounted for under this IRP process, there is a clear risk that at some point in time they will be included as regulators seek to achieve real emissions reductions. Multiple studies indicate that fully accounting for these emissions brings the natural gas supply close to emissions intensities associated with coal combustion. Non-zero emissions allowances and optimistic emissions factors for natural gas create conditions where building natural gas fired systems is the most cost effective response to declining GHG levels. The concern is that when emission limits fall to absolute zero, significant (approximately doubling) costs will be incurred to sequester the carbon output of these plants. Please ensure that all models can add multiple interconnections and run scenarios that study zero GHG	The Salisbury - Quebec HVDC resource option was offered to the model in all Regional Integration scenarios; both the Quebec and Coleson Cove transmission expansions fall into the definition of Regional Interconnection as used in the IRP. NS Power, through the standards for Quantification, Verification and Reporting, does not account for upstream fugitive emissions. Should this become legislation and the impacts material, any future planned natural gas units would be re-evaluated. NS Power will continue to monitor regulatory developments in this area and update its analysis, via the evergreen IRP process, as appropriate. NS Power agrees that assessing import options continues to be critical to future resource planning and intends to continue this work via the Regional Integration Strategy proposed in the IRP Action Plan.

Category	Comment #	Comment	NS Power Response
		conditions. It is critical that this IRP fully assess the import options available to Nova Scotia.	
Load Forecast Data Requests	Hendriks-01 Richard Hendriks	Detailed historical data requests, additional analyses and comments seeking information on items already covered through the stakeholder engagement process, or Assumptions already finalized through stakeholder consultation. The decision to maintain the endpoints consistent with the established SDGA goals requires further justification. Historically, the effect of substantive economic contraction on electricity demand is a modest to substantial downward (or rightward) shift in the demand curve following the recession, for both energy and peak capacity. Not accounting for this shift in the load forecast potentially creates a systemic bias across all findings in the IRP. Requested last 20 years of load forecasts; analysis of recessionary effects on demand.	The requestor advised that he is a PhD student at the University of Toronto and did not identify an interest related to electricity planning within Nova Scotia. In many instances the information sought is found within materials released to stakeholders earlier in this process. The detailed data requests and additional analyses and explanations sought are beyond the scope of the IRP.

Category	Comment #	Comment	NS Power Response
CTs	HG-01 Heritage Gas	The liquid-fueled CT's are now over 40 years old. The model scenarios include the continued use of these units to 2045, by which time they will have been in service for over 60 years. Heritage Gas understands that fuel delivery to these units is by tanker trucks and, as a result, replenishment of the tanks that support these units is reliant on the availability of a limited pool of tanker trucks. This pool is further constrained in winter months when the units are more likely to be called upon. Availability of fuel supply has decreased following the closure of local refineries. Reliability issues associated with maintaining units out to their sixth decade of operation should be considered independently of the economics of replacement vs sustaining capital costs. Reliability test results should be made available to IRP stakeholders.	As discussed at the July IRP workshop, NS Power has invested in the diesel CT units over the last several years to enable continued reliable operation. The Resource Screening results show that the capacity provided by these units continues to be required and is lower cost than alternative capacity sources by a wide margin.
Electrification	HG-02 Heritage Gas	Given that IRP outcomes can influence long-term capital investments and policy directions, the total cost implications of IRP outcomes for rate payers should be examined in the Action Plan. Increased electrification will contribute to peak energy demand. A number of studies have shown that natural gas distribution systems can cost effectively assist in meeting peak energy demand while still meeting GHG targets. The nature of the results of the IRP analysis and the significant reliance on natural gas going forward in all scenarios provides an opportunity for Heritage Gas to work with all stakeholders to ensure the most cost-effective energy supply system in the province going forward.	Based on feedback respecting challenges associated with comparing scenarios reflecting differing load levels due to electrification, NS Power has provided rate analysis with the draft Findings release to provide a better comparison across plans to understand implications for ratepayers.

Category	Comment #	Comment	NS Power Response
Compressed Air Storage	Hydrostor-01 JFS Hydrostor	We believe that A-CAES's capital costs were inaccurately modelled. We believe that this played a decisive factor in it not being selected as a preferred resource. In particular, we found that in your cost analysis, the model used a $/kW cost of CAD $2,200. This was in effect, the mid point of our $/kW cost estimates for a 200 MW facility with a duration of 12 hours that we had previously provided to you. This was then compared to the cost of a lithium-ion system with 1 and 4 hours of duration…. If you consider a 500 MW facility with a 4-hour duration, the cost works out to an average of US$1125/kW. We believe that this is a much fairer comparison to a 4-hour lithium-Ion system for the short duration market. CAES can act as a non-wires alternative to traditional transmission for improving reliability or as a solution for integrating and time-shifting Nova Scotia's wind resources onto the grid. A-CAES uses spinning turbines it can meet the grid's need for inertia and synchronous generation. Furthermore, unlike pumped hydro or fossil assets, A-CAES can be flexibly sited where the grid needs it.	NS Power's Final Assumptions provided ranges for costs for storage options which may be provided by a variety of technologies/sources. Hydrostor's specific technology was determined to be within this range. As previously stated, the resource technology selection is indicative for the specific scenario. For future resource procurement, NS Power would undertake a detailed Alternatives Analysis to target the specific technology if there are competing alternatives with similar attributes (e.g. RECIP vs CT, battery vs other storage option, etc.).

Category	Comment #	Comment	NS Power Response
Wind cost	NF-01 Natural Forces	Price of wind is overstated compared to observed current pricing. NS Power should reduce by 30 percent at a minimum. Capacity factor used is much too low leading to the high price. NSPI has strong opinion on this issue and it is suggested that it would make sense to test the sensitivity of this pricing. The model should be run with a sensitivity of a reduction in cost of 30% at a minimum.	NS Power undertook two Low Wind Price Sensitivities (see 2.1C.Wind-1, 2.1C.Wind-2) which both include wind capital costs at 29% below the base case assumption. Capacity factor assumptions were developed by E3 based on CanWEA pan-Canada wind integration study and reflect higher capacity factor assumptions than current operational wind farms in Nova Scotia.

Category	Comment #	Comment	NS Power Response
Wind cap	NF-02 Natural Forces	Wind is capped at 700 MW unless tie, batteries, condensers built. PSC study was based on stressed conditions and severe contingencies and does not apply to typical system conditions. Wind is being limited to allow larger amounts of import. Consider prioritizing internal resources during system stress. The capital cost of the associated investments have the effect of making wind a non-viable proposition for at least the first ten years or so of the model period. PSC study doesn't recommend limiting wind installed capacity. Its findings can be addressed via operational practice during stressed or contingency occurrences. Example from Ireland. The Study findings do not conclude that the wind installed capacity must be limited to 700 MW. All that they conclude, is that in certain stressed system conditions, the output of the wind should be temporarily limited to 700 MW.	Contingencies are not scheduled, and therefore the system cannot be pre-set to manage these contingencies. Contingencies can occur at any time and without warning. To pre-set the system to be capable of surviving a contingency, wind output could have to be curtailed, potentially at all times depending upon the amount installed, or the import would not be scheduled. Such a structure would imply that load is not being economically served. Pre-curtailment of imports is not economic based on the significant quantities of non-firm imports that are being economically dispatched in all scenarios. NPCC and NERC criteria state the contingencies for which the system must be operated at all times in preparation for. NS Power's draft findings concluded that further work is required to assess system stability at significant invertor based renewable energy penetrations and determine whether additional dynamic system inertia constraints or other ancillary services can enable higher levels of integration on the Nova Scotia system. This study will further refine system integration requirements (e.g. the requirement for new integration assets, operational practices or enabled through existing technology on new resources).

Category	Comment #	Comment	NS Power Response
Inertia	NF-03 Natural Forces	System inertial response requirement is over-stated. The minimum level of 3,266 MW is not well substantiated based on the PSC study. It appears that there is a safety margin of one thermal generation unit included in the PSC study, and then a further safety margin approximating to one thermal generator added in the IRP study. This appears on face value, to be unduly conservative. The SIR requirement is arising from high imports on the AC intertie. At times of lower import levels, the SIR requirement would be expected to be much lower. Monitor industry developments around synthetic inertia.	NS Power agrees that it will monitor industry developments around synthetic inertia. NS Power met with interested stakeholders and completed modeled a sensitivity that lowered the inertia constraint to 2200MW.sec (2.1C.WIND-3) which found that lowering this constraint did not have a significant effect on the resulting optimal resource plan.
Load forecast	NF-04 Natural Forces	Covid effects are too severe and prolonged. Should use something like 2-5 years instead of 10 years.	The pandemic load sensitivity was determined to provide a reasonable low-end sensitivity in consultation with IRP stakeholders.

Category	Comment #	Comment	NS Power Response
Transition plan and wind adds	NF-05 Natural Forces	Transition plans are needed to replace generation, which doesn't happen instantaneously - a new build and a retirement take place over long periods. Any transition plan is likely to involve adding wind year-by-year over the period up to 2030, determining the correct results from the SIR requirement and the hard cap on wind until a 2nd intertie is of crucial importance. If the position is maintained that wind installed capacity in excess of 700 MW must be accompanied by either the 2nd AC intertie or by BES/synch comps, then these would have to be built out in tandem with the wind. This could result in a premature and/or unnecessary level of capital expenditure, increasing costs to consumers	NS Power agrees that the system transformations indicated in the IRP scenarios will require cautious planning. The draft Findings release has recognized this point. Based on this and similar feedback, modeling assumptions were updated between the Initial Portfolio Study and Final Portfolio Study to limit the number of steam units that could retire in a single year. NS Power will continue to study wind/invertor based renewable energy integration requirements and how changes could impact the optimal quantity and timing of these resources.
Interconnection energy flows	NF-06 Natural Forces	Interconnection energy flows shown in aggregate. Can the import and export energy flows be provided? Also pricing of exports.	Information has been provided in a manner that protects commercially sensitive details for the benefit of customers.
ELCC of imports	NF-07 Natural Forces	Only firm imports are assumed to contribute to the ELCC. This is not the case in Europe.	Only firm imports can contribute to the capacity requirement established via the firm peak forecast and Planning Reserve Margin requirement. Without a firm import arrangement with a market or counterparty and firm transmission access to deliver, NS Power could not reliably expect access to capacity/energy during a peak event.

Distributed Resources	Quest-01 Envigour / QUEST/ Marine Renewables Canada	DERs are considered a reduction in system demand without a cost to the system. How does this assumption fit within the requirement to allow for Enhanced Net-metering by customers. Assuming DERs as reduced demand for system electricity likely undervalues the potential positive contribution to the system that could come from a combination of DERs such as solar PV and storage by customers. We understand NS Power is exploring this potential through the NS Smart Grid project and related initiatives. The benefits from resiliency and reliability offered by DERs may be part of your planned next step runs and scenario testing. If so, information from that process may help gain insights into the value of DERs, especially when combined with storage. However, we believe there will likely be the need for additional discussions on these matters, and how to incorporate them into the Roadmap. Also, several NS Municipalities have expressed interest in Community Solar PV Gardens. It would be useful to discuss whether this concept is the same as DERs from the model's perspective and, if not, how it may be considered as well.	The NEM arrangement allows customers to offset their consumption with the production from their DER (primarily solar PV) and sell excess surplus energy to NS Power. Site installations are sized to offset annual generation (maximum size); thus excess sales to NS Power are very limited. NS Power's Distributed Resources Promoted resource strategy would be consistent with this program, wherein the Net System Requirement (Load) is reduced by high DER uptake. While solar (both utility scale and BTM) is not cost competitive in the near to mid-term with other candidate resources, as indicated by the lack of economically selected utility-scale solar in the IRP scenarios, this Resource Strategy was reflected how the NEM program could incentivize installations; being able to offset consumption at the retail rate. Other factors (e.g. ESG, technology advancement, policy, financing structures, etc.) could also lead to more DER uptake. NS Power agrees that it does not account for possible value sources from paired solar PV with battery storage. Without a firm understanding of NS Power's access to customer sited battery installations, and under what conditions, it would be highly speculative to model such value sources. NS Power agrees that the Smart Grid Atlantic Project and a continued analysis on the potential of DERs to provide distribution level savings will be important as these technologies develop and mature.

Category	Comment #	Comment	NS Power Response
			NS Power did not distinguish between rooftop solar and community solar gardens.
Future Generation Technologies	Quest-02 Envigour / QUEST/ Marine Renewables Canada	The model did not select several potential technologies such as offshore wind, tidal or hydrogen. It would be useful to know what the gap was between these technologies and the ones are chosen. It would help us understand the degree price reduction required to make them competitive in the future. Furthermore, it would be useful to know how the model would have valued any of the unique properties associated with these technologies, such as the predictability of tidal. If they were not valued, what process or opportunity might we see in the future to gain better insight?	NS Power did not have detailed assumptions for resources powered by hydrogen. NS Power has proposed to monitor low and zero carbon fuels in its IRP Action Plan and Roadmap The nature of the optimization in an IRP process does not lend itself to this type of analysis. A dedicated optimization process would need to be undertaken to assess these non-traditional resources, which is outside the scope of this IRP.

Category	Comment #	Comment	NS Power Response
Natural Gas	Quest-03 Envigour / QUEST/ Marine Renewables Canada	The narrative suggests a CCGT solution appears in several runs. We recommend there be a fuller discussion of the costs and benefits associated with an investment in this area. We would consider what kind of pathways/solutions would be necessary to achieve a net-zero electricity system by 2050 with a CCGT investment to be a priority. We would also want to identify and quantify the risk to electricity reliability from a dependence on a single natural gas pipeline. Identifying the risk of not being able to have local storage of natural gas should also be explored from a reliability perspective.	As part of NS Power's draft Action Plan, it has proposed to develop a plan for the redevelopment or replacement of existing natural gas-powered steam turbines to provide low-cost, fast-acting generating capacity to the Nova Scotia system. Fuel flexibility is a component of this work, including consideration for low/zero carbon alternative fuels. In the higher priority scenarios (e.g. 2.0.C, 2.1.C), combined cycle units are not built until 2040. By this time, there will be greater certainty on the viability of this resource given the associated carbon policy and/or developments in alternative fuel sources which minimize this risk (e.g. hydrogen or CCS) NS Power agrees that the economics and permitting considerations of natural gas storage vs pipeline reservation and reliability considerations of n-1 contingency would need to be considered.
Contribution to NS economy	Quest-04 Envigour / QUEST/ Marine Renewables Canada	Each of the scenarios has a different impact on the NS GDP. Will the IRP process be able to differentiate which scenarios would more likely use NS sourced goods and services on a CAPEX and an OPEX basis?	This is not within the scope of the IRP.

Inertia	SBA-01 Small Business Advocate	Since the system inertia requirement is a constraint in the modeling, the Company should provide more analysis and detail supporting the assumptions. The PSC study provided initial results, but the Company acknowledged several shortcomings at the time. The IRP analysis would be more complete with the following: More information on derivation of requirements and cost of alternatives to generation such as synchronous condensers, and information on any limitations on the amount of these that the system can rely upon. Additional analysis supporting the inertia benefits ascribed to the Reliability Tie. The modeling currently assumes the reliability tie would provide all system inertia requirements for system. Are there limitations to this assumption, or are there system conditions (in NS or NB) under which the tie would not provide the claimed inertia benefits? NSPI should conduct additional analysis to identify the minimum amount of inertia requirements in province under different system conditions. The 3266 MW.sec requirement was based on specific load conditions resulting in a 2766 MW.sec requirement, plus a 500 MW. eg generic additional requirement. Additional analysis would allow for more dynamic modeling of this requirement and provide additional insight on the inertial need over time as load, DSM, and supply-side portfolio mix changes. Since ascribing this benefit of providing all the inertia requirements is uncertain and very valuable to the evaluation we would like to see a sensitivity if the inertia benefits of the tie is substantially lower than assumed, such as providing only half of system inertia need. Provide information regarding whether the battery+ synchronous condenser option for system inertia would also provide system capacity.	NS Power will continue to advance modeling of system inertia constraints. As part of its updated modeling results released with the draft Findings, the following additional constraints were tested: -A Low Inertia test case was included (at 2200 MW.sec) -A No inertia / no integration requirement test case -a case where the Reliability Tie provides 50% of system inertia requirement (1633 MW.sec) The IRP model does not limit the quantity of online inertia that can be supplied via synchronous condensers; this limit will be recommended for examination in future work. Dynamic modeling of this constraint is also an opportunity for future work post-IRP. When wind is integrated using the Battery + Sync. Condenser option, the batteries do provide firm capacity according to their ELCC curve and contribute to the PRM.

Category	Comment #	Comment	NS Power Response
Reliability Tie and Regional Integration	SBA-02 Small Business Advocate	Treatment of risk: The Reliability Tie and Regional interconnection are significant components of the initial modeling results and would represent substantial investments. Given the scope of the investment it is important to understand the risks associated with the investment, and the cost of alternatives. What additional studies will be required if the reliability tie or regional integration plan is selected? What would be the schedule for those studies? For each portfolio that selects a transmission upgrade as part of a least-cost plan, NSPI should provide results demonstrating the incremental cost of the non-transmission option so the Board can balance the cost against the risk if the transmission investment is not fully utilized or if a lower cost option becomes available. This should be clearly considered within the decision process to choose a preferred portfolio.	The Reliability Tie and Regional Interconnection options have been selected in multiple plans, indicating that they provide value for customers over alternative resource options. NS Power has proposed an Action Plan item for post-IRP evaluation that would include detailed Transmission Planning Analysis, route options analysis, construction cost studies, and engagement with other jurisdictions.

Category	Comment #	Comment	NS Power Response
Renewable Resource	SBA-03 Small Business Advocate	The Company assumes onshore wind is the primary renewable resource as part of the future portfolio. Other areas on the Atlantic coast of North America are focusing on offshore wind to provide resource diversity. Did the Company's analysis fully incorporate the benefits of diversity of· timing of production (e.g. through the ELCC analysis)? If the costs of offshore wind come down considerably over the study period, are there planning decisions (such as transmission investments or conventional capacity additions) included in this IRP that would be rendered unnecessary? The Company should provide sensitivity modeling that would help understand this issue.	Onshore wind has been economically selected in all IRP resource plans as a low-cost local source of renewable generation The E3 supply options study (from the Pre-IRP work) indicated that the cost of offshore wind was approximately 2.25 times greater than onshore wind per installed kW in Nova Scotia, although the cost decline over the planning horizon was larger. Ongoing O&M costs are estimated to be 2 times more expensive than onshore wind. In addition, the Capacity Factor midpoint is estimated to be 41% for offshore wind, 2% higher than the 39% assumed in the IRP for new onshore wind. From an integration perspective, offshore wind would have similar integration requirements as onshore wind and so could be integrated in future resource plans in place of other inverter-based variable renewable generation if costs or other factors were to significantly change.

Metrics	SBA-04 Small Business Advocate	Now that the initial modeling is complete and stakeholders have greater understanding of the inputs and analysis, it would be useful to have a stakeholder exchange or technical session and the opportunity for written comments specifically focused on proposed metrics from NS Power. We offer the following additional comments: Current proposed metrics appear to be revenue requirement minimization over a long horizon since the modeling calculated PVRR utilizing a real levelized capital cost recovery factor in modeling. We would like to see the corresponding values utilizing nominal accounting cost recovery or revenue requirements. GHG metrics presented with initial modeling results include totals over the study period and includes some GHG Marginal abatement cost. The Company should provide annual GHG production metrics in tons and in percent of a baseline historical year emissions. The preliminary results included a metric calculating an average cost of generation, but the Company was uncertain as to whether it would be used going forward. The Company should provide metrics to help provide insight on affordability of each portfolio, perhaps showing annual cost of electricity impacts utilizing nominal capital cost carrying charges. Generally, the more capital a company commits to invest in a portfolio the greater the risk. The Company should provide a metric calculating total average capital investment requirements over the first five years, ten years and twenty years. It is important to have visibility on how much NS Power will be relying upon imported power as a metric, such as average	NS Power has refined the definition of several metrics as part of the September 2, 2020 draft Findings release, and has incorporated much of the feedback noted here, as well as that received from other stakeholders and during subsequent discussions with individual IRP participants. NS Power uses nominal input values, and thus a nominal discount rate when calculating NPVRR. The model levelizes new capital investments via an annuity method, while other costs (e.g. fuel, OM&G) are expensed in the year incurred) to be as consistent as practical with actual accounting treatment. In particular, rate impact estimates, GHG production, and reliance on imported power (as a component of plan robustness) have all been included with the draft Findings release.

Category	Comment #	Comment	NS Power Response
		annual imports over the first five years, ten years and twenty years.	
Metrics	SBA-05 Small Business Advocate	Metric Definitions: The Company should provide written formulas and examples for the calculation of each metric used in the portfolio analysis. Scoring or Metric Trade-off Analysis: The portfolio analysis will likely utilize some method of weighing (explicitly or implicitly) the various metrics when choosing or creating a preferred portfolio. The Company should provide a detailed description of how the various metrics will be used.	Additional refinement to metric definitions is included in the September 2 release.

Category	Comment #	Comment	NS Power Response
Process	SBA-06 Small Business Advocate	The Company has maintained extensive communication and stakeholder engagement efforts during the development of the pre-IRP deliverables, and we hope that going forward the process will remain transparent and collaborative. To that end, we recommend technical sessions or the opportunity for written comments on the following areas: a. Metrics choice - Recommend written comments exchange after distribution of NS Power proposal. It is critical to finalize the metrics collaboratively before reviewing modeling results for findings. b. Detailed review of analytical results - Recommend technical session, in particular detailing results of any analysis of system operations. c. NS Power initial findings and conclusions - Recommend the Company issue findings and conclusions, solicit comments, and hold a stakeholder feedback and discussion session. d. Road Map & Action Plan - Recommend the Company issue drafts, solicit comments, and perhaps hold a stakeholder discussion session. Assure that road map lays out all studies and approvals necessary and key decision points. e. Report- Recommend the Company issue draft comments, incorporate comments into final and have all comments in an Appendix.	NS Power has continued the significant participant engagement that has occurred so far during the IRP process. This has included opportunities for participants to comment on the updated modeling results, Draft Findings/Action Plan / Roadmap, and Draft Final Report in advance of the Final Report being submitted. All comments will be provided in an Appendix to the Final Report.

Category	Comment #	Comment	NS Power Response
Stranded Assets	VC-01 Verschuren Centre	It is counterintuitive that building 764-1170 MW of additional fossil fuel capacity is most appropriate. It should be expected that all of these assets would have minimal economic value in a zero carbon system, or after 2050. Does the Plexos model consider stranded assets in 2050 (beyond the planning horizon), especially for those units installed in 2040 in 2.x Scenarios?	As part of NS Power's draft Action Plan for the redevelopment or replacement of existing natural gas-powered steam turbines to provide low-cost, fast-acting generating capacity to the Nova Scotia system. Fuel flexibility is a component of this work, including consideration for low/zero carbon alternative fuels. Resource technologies utilizing natural gas feedstock were not excluded as candidate resources. In scenarios that build the high utilization Combined Cycle gas units, do so late in the modeling horizon (e.g. 2040 for 2.1.C). By this time, it is anticipated that there will be more certainty on the viability of this resource given the prevailing carbon policy and/or developments in alternative resources or fuel sources which could minimize this risk (e.g. hydrogen or CCS). The Plexos model does not consider stranded assets beyond the planning horizon.

Inertia	VC-02 Verschuren Centre	The table on Page 8 of the modeling results indicates that inertia factors for wind energy and energy storage were not considered in the model. As wind energy and batteries are low cost sources of energy and carbon free capacity, the decision to exclude them will have negative impacts for customers. There is a growing body of evidence that suggests both technologies can contribute to system inertia. Many of the existing fleet of Nova Scotia wind turbines, including some of those owned by NS Power, are inverter-based machines that could provide synthetic inertia. Future procurement of wind turbines could include this. Lithium Ion Battery systems would also have an inverter-based interface with the grid, they too would be able to provide synthetic inertia to the grid. Some utilities in North America are already seeing proven results from this effort, and others are starting additional testing. Please provide indication of where in the modelling the Inertia Constraint was binding and resulted in a choice of fossil fuel generator over batteries 3. Did the inertia constraint impact the decision process of the Diesel CT Screening? 4. Please consider a screening, which evaluates a 3.x scenario with inertia qualities applied to existing wind turbines, future wind turbines, demand control and battery resources.	As part of its updated modeling results released with the draft Findings, the following additional constraints were tested: -A Low Inertia test case was included (at 2200 MW.sec) -A No inertia / no integration requirement test case -A case where the Reliability Tie provides 50% of system inertia requirement (1633 MW.sec) The IRP model does not limit the quantity of online inertia that can be supplied via synchronous condensers; this limit will be recommended for examination in future work. Dynamic modeling of this constraint is also planned for future work post-IRP. Plexos LT module optimizes candidate plans constrained by all ancillary services (reserve) constraints. This is achieved by integrating reserve constraints into the mathematical framework for dispatch and pricing. The suite of the new resources including batteries and wind are contributing to certain modeled ancillary services. Batteries contribute to all types of reserve including regulation (raise and lower), spinning and non-spinning. Transient system stability studies, which assess FFR in timescales of seconds (or less), are outside the scope of long-term planning studies. As FFR was not assessed in the Plexos framework, its presence or absence is not expected to have an impact on expansion/retirement decisions. However, if FFR services are found to reduce the synchronous inertia constraint as modeled, the plan could change.

Category	Comment #	Comment	NS Power Response
			The draft Roadmap item included in the draft Report provides: 2. Complete detailed system stability studies under various current and future system conditions, reflective of both stressed system states and normal operating conditions, while considering higher quantities of installed wind capacity as seen in the IRP modeling results. This work will also consider the impacts of grid service provision from inverter-based generators such as wind turbines and how the introduction of new services like Fast Frequency Response might affect existing requirements such as Synchronized Inertia. Monitor results for significant divergence from wind integration assumptions modeled in the IRP and trigger an update as needed.