Category	Participant	Comment	NSP Response / Consideration for Final Report
Sensitivity	CA	(1) Will cost sensitivities be performed on selected portfolios (e.g. fuel costs)?	Yes. In addition to the sensitivities previously published, NS Power has added three new cost-related sensitivities to the Modeling Results in parallel with the release of the Draft Report. Two sensitivities were added examining high and low sustaining capital costs for existing thermal units, and a third was completed which examined a high cost sensitivity on pricing for Natural Gas and Import prices, since those resources were seen to have a prominent role in most of the key scenarios and sensitivity optimal resource plans. Additional details on the results and interpretation are available in the updated Modeling Results file on the IRP website.
Rate impact	CA	(2) The individual model run results refer to "average annual partial rate impact" but the summary slide "relative rate impact comparison" does not reference the word "partial." Is there a difference between what is being shown on the relative comparison slide and the individual model run result summaries?	No. The average annual partial rate impact from the individual model runs have been calculated using the *Rate Impact Model* described in Section 5.3.4 of the Draft Report.
Operating Reserve	CA	It is not clear whether Plexos makes unit commitment decisions to satisfy operating reserve requirements and meet inertia constraints sequentially or through co-optimization. Regardless of the answer, the interaction between these two requirements seems to be a significant driver of model output, and NS Power should verify that it has configured its model in a manner that handles all of the sensitivities in a reasonable manner.	PLEXOS co-optimizes the energy dispatch and provision of ancillary services in both the PLEXOS LT and PLEXOS MT/ST modules.
Sensitivity	CA	General model configuration decisions may affect sensitivity runs in ways that were not evident in the testing for the main cases. For example, the chronologies used in Plexos LT testing may have been optimal under the default assumptions around inertia but may not capture the different challenges of operating with lower inertia constraints, which are only tested for the 2.1C case. (3) Please provide discussion of the issues NS Power has evaluated in its model configuration decisions.	NS Power has input consistent model configuration parameters for all scenarios and sensitivities modeled in the Final Portfolio Study; this is important in ensuring that output results are comparable from one scenario to another.

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Wind	CA	Either battery storage or operational practices would have some impact on the economics of the wind procurement. Our review of the model results suggests that wind resource pricing is a more significant driver than considerations of reliability. Reducing the inertia requirement advances a small amount of early wind (2.1C v 2.1C.WIND-3), but also delays wind investment in the 2030–2033 period. (4) RII recommends that NS Power adopt a finding that because the primary driver of wind resource procurement levels is price, the most important step NS Power can take to identify the appropriate level of wind investment is to conduct an all-source RFP. The draft action plan's resource procurement strategy should be significantly revised. NS Power suggests a wind procurement strategy and a plan for redevelopment or replacement of steam turbines with combustion turbines. As discussed above, the most significant uncertainty in determining the timing and scale of new resources for NS Power is the cost of wind power and battery storage. Under the most favorable cost assumptions, NS Power could acquire as much as 300 MW of wind in 2023 and 676 MW of wind by 2026. The wind and battery price sensitivities also affect the timing and size of near-term CT procurements. RII recommends that the draft action plan be revised to pursue an all-source Wind, reliability tie and regional integration decisions should be co-optimized. It should be recognized that if a high level of wind resources are procured, and those resources depend on the reliability tie, then any schedule delays affecting the reliability tie can be managed with temporary operating constraints on the wind projects. (21) Planning for transmission should proceed in parallel to an all-source RFP. Cost estimates for completion of the reliability tie for different in-service dates (several options, covering the range from the earliest feasible date to 2032) should be developed for use in bid evaluation. The regional interconnection should be handled similarly, except that there will be need for fewer in-service date options and accompanying cost estimates since the near-term resource acquisitions should be less sensitive to the exact date and cost estimate. Given some of the sensitivity results, the potential in-service dates for this project should be expanded to cover 2028-2040.	NS Power agrees that the modeling indicates that the low wind pricing has a larger impact on expansion decisions than the reliability inertia constraint. NS Power has updated IRP Roadmap item #8 to indicate that "NS Power will solicit Nova Scotia-based market information" to inform installed costs of wind. This is also captured in additions to IRP Action Plan item #3d which indicates that the wind procurement strategy "will solicit Nova Scotia-based market pricing information which will inform the selected wind capacity profile and timing, informed by the IRP wind sensitivities". The IRP scope does not include findings or recommendations on specific procurement approaches. Wind, reliability tie and regional integration decisions have been co-optimized in the IRP modeling results. NS Power has updated its Action Plan to reflect comments on wind integration requirements in parallel or prior to, the in-service date of the Reliability Tie. Please see Action Plan item #3d. NS Power will consider the comment on assessing costs for different in-service dates for the Reliability Tie and how it could impact future resource procurement/expansion decisions, and whether different operating limits could be enforced in advance of wind integration measures such as the Reliability Tie.
	CA	There seems to be a trade-off between imported power and battery resources. Surprisingly, Case 2.0A.Import-2 indicates that both batteries and CTs are procured at relatively high levels, allowing additional retirements of steam units. This suggests some interesting interplay between battery resources and thermal unit operations that the modeling may not have explored fully. As was discussed on a call with NS Power, the model did not value synthetic inertia and other advanced applications of battery storage that could have a significant effect on advancing retirement decisions for steam units in favor of advancing new resource acquisitions.	Sensitivity case 2.0A.IMPORT-2 assesses the absence of the ability to build the Reliability Tie – a wind integration resource/asset. The other option for integration of more than 100 MW of wind, as developed during the Renewable Stability Study, is the domestic option which consists of incremental battery and synchronous condenser resources. NS Power interprets the additional battery storage seen in this sensitivity as a method of wind integration in the absence of the Reliability Tie. As suggested, gas and the incremental batteries discussed above are providing firm capacity, which enables earlier coal retirement than the Base scenario. While the optimization algorithm appears to be finding synergies between battery and gas capacity and coal retirement, a portion of the battery additions is mandated for the wind additions (along with synchronous condensers). The overall scenario appears to be higher cost than the base case; the batteries are required for wind integration in the absence of the Reliability Tie and the model utilizes the firm capacity they provide to enable incremental retirements to reduce the cost gap to the base case.

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			The PLEXOS LT module optimizes candidate plans constrained by all ancillary services and 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 is contributing to certain modeled ancillary services. Batteries contribute to all types of reserve including regulation (raising and lowering), spinning and non-spinning. Transient system stability studies, which assess fast frequency response (FFR) in timescales of seconds (or less), are outside the scope of long-term planning studies. As FFR was not directly modeled in this IRP, its presence or absence is not expected to have an impact on coal retirement decisions. However, if FFR services are found to reduce the synchronous inertia constraint, the economics of coal retirement with battery replacement may improve (based on the FFR requirement and a battery's specific contribution). NS Power believes that effective load carrying capacity (ELCC), capital and operating costs, provision of reserves, and the amount of variable renewable energy on the system are the primary drivers of battery additions in the IRP modeling.
Battery	CA	(5) Please explain why battery capacity drops in 2045, identify the resources the model substitutes for battery capacity, and discuss implications of late-model treatment of battery storage in the end effects calculation.	Capacity reductions (or removals) of battery storage resources in the late years are the result of a battery(s) reaching the end of its modeled 20-yr technical life. Replacement of retired battery capacity is based on economics and/or the planning reserve margin (PRM) constraint, and thus, it is not necessarily replaced or may have been replaced with a different resource type. The PLEXOS LT formulation includes an attribute that accounts for end effects. The model assumes that last year of the horizon is repeated an infinite number of times. The objective function is expanded by the cost of the years after the final horizon year (2045). The exogenous calculation of end effects only includes costs of the 2045 portfolio. Thus, if there are no operating battery resources in this year, end effects would not assume any future costs for battery resources.
Transmission	CA	Results do not show the expected effects on the timing of the reliability intertie as its inertia benefits change. The reliability intertie is built earlier when the level of inertia it provides is reduced (2.1C.IMPORT-3) or the price of batteries, an alternative source of inertia, is reduced (2.1C.WIND-1 vs WIND-2). On the other hand, some model results indicate that the timing of the reliability intertie reflects the demand for inertia. Reducing the need for inertia results in delaying the reliability tie (2.1C vs 2.1C.WIND-3 and WIND-4). RII recommends that planning for potential transmission projects proceed.	NS Power notes that the magnitude of timing changes noted here is relatively minor in a resource planning context; for example, moving from 2.1C to 2.1C.IMPORT-3 (Limited Reliability Tie Inertia) advances the build of the Reliability Tie by 2 years, while moving from 2.1C to 2.1C.WIND-3 (Low Inertia Constraint) delays the build by 1 year. NS Power also notes that batteries do not provide a source of synchronous inertia in the IRP modeling assumptions; batteries as modeled are not an alternative source of inertia. NS Power believes it is generally appropriate that the Reliability Tie would be advanced in cases with low-cost wind, as this is generally seen as the lowest-cost integration asset (for large wind resource additions). NS Power agrees with the recommendation for transmission planning to proceed and is this is reflected in Action Plan item #1 for both the Reliability Tie and the Regional Interconnection.

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Wind sensitivity	CA	We see extraordinary sensitivity to relatively modest drivers. For example, lowering the battery cost results in delaying regional integration by 10 years (2.1C.WIND-1 vs WIND-2), even though the additional battery capacity is negligible compared to the imports available through regional integration. NS Power indicated that the model might be seeking to optimize a transition to a more adaptive resource mix, and that some of these interactions might be enabling higher retirements of "slow inertia" units. This concept is consistent with the model output from 2.1C.IMPORT-3: with the reliability tie providing less inertia, more "slow inertia" steam units retire, to be replaced by additional imports, combustion turbines, and wind (presumably for the energy). It appears that the domestic CTs are being utilized more heavily for inertia and other services in this scenario. (6) Please discuss the trade-offs of the benefits and indirect impacts of transmission and related reliability measures. (7) Please clarify how the concept of "slow inertia" modifies the inertia values by unit that NS Power provided previously. Does "slow inertia" refer to the long start-up times of steam units before they can provide inertia? How does inertia vary with the operating level of a steam unit? (8) Are unit commitment costs for inertia and/or operating reserves a driver in determining the transition pace from existing to 2040 resources?	From a reliability perspective, NS Power has modeled the contribution of the Reliability Tie to the synchronized inertia constraint and has used it as a mechanism to enable wind integration. Firm imports accessed via the Regional Interconnection contribute to system reliability via the PRM. No other reliability benefits of transmission are modeled in the IRP PLEXOS model, although they do exist from a contingency analysis perspective (not in IRP scope). There is no differentiation between different inertia types in the model (e.g. "slow inertia" as discussed in the letter of comment); rather, the model is constrained by steam unit minimum up and down times (and is penalized by unit start costs) which would suggest that a more flexible system could meet the inertia constraint as modeled at a lower cost. Inertia provision from generating units does not vary with unit output; the contribution from each unit (as provided previously to stakeholders) is constant as long as the unit is online. Unit commitment costs are integrated into the optimization model and co-optimized with generator dispatch and ancillary service provision; it is likely that inertia and reserve constraints have an influence on retirement pace for this reason. More broadly, as the system transitions to a resource mix with more variable generation, the benefits of more flexible units become apparent both for meeting ancillary service requirements and for dispatching against higher levels of renewables.
Reliability tie	CA	(9) Does the reliability tie provide any services other than inertia, such as reserves or load following?	It is modeled only as providing synchronized inertia and enabling wind integration beyond an incremental 100 MW. It may provide additional benefits that were not assumed for modeling purposes.
Reliability tie	CA	(10) Is the increase of imports with the reliability tie a result of the reduced need to commit domestic steam units?	This is a logical correlation, as with the inertia provided by the Reliability Tie there is less requirement to keep steam units online at lower loads. This energy could be replaced by imported energy. NS Power looked at several scenarios, and the difference in imported energy in the year prior to and the year following construction of the Reliability Tie was generally a relatively small increase, e.g. in Scenario 2.0A comparing 2031 and 2032 or Scenario 2.0C from 2029 to 2030.
Reliability tie	CA	Understanding the relationship (transmission, wind, battery, inertia) will be critical prior to issuing an all-source RFP, since non-domestic resources may wish to bid into the RFP based on varying assumptions about the completion date for a reliability intertie.	NS Power has stated in the Action Plan that the development of the Reliability Tie will commence immediately following the conclusion of the IRP, in order to continue to develop this information as quickly as possible and inform future resource procurement and development activities. NS Power has committed to further develop its Regional Integration Strategy to assess what path offers the greatest value to customers.
Solar	CA	Wind outperforms solar, but is that the only reason that the model does not select much solar for the portfolio. NS Power should discuss in its findings the role of firm and non-firm imports in meeting the carbon emission limits. It is our understanding that NS Power assumes that imports are exclusively or primarily low- or zero-carbon resources. (12) Are the import prices based on the costs of renewables in other provinces?	The IRP model assumes Canadian-sourced imports are emissions free, as emissions are accounted for in the producing jurisdiction via provincial regulations. Sources from non-Canadian markets have an emissions profile consistent with the Quantification, Reporting and Verification Regulations (QRV) that NS Power currently follows for emissions accounting. The firm imports via new transmission have an emissions profile based on jurisdictional emissions forecasts, adjusted via the pricing forecasts for the Regional Greenhouse Gas Initiatives (RGGI), consistent with QRV guidelines.

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		(13) If imported power has some significant level of carbon emissions, would solar be more attractive?	Pricing for energy and capacity available via the Regional Interconnection was provided via a fundamental forecast by Platts Analytics and is based on forward NEPOOL prices. Solar's emissions-free energy profile would be considered against firm/non-firm imports with and without emissions and all other resource options in the optimization process. NS Power notes that in the few cases where solar appears, it is selected in the late years of the 3.X Accelerated Net-Zero 2045 scenarios when emissions are most constrained; this suggests that emissions reductions under very limited GHG caps are a primary driver of solar additions in the model.
Covid	CA	Include impacts of current global economic recession on NS Power's load and the implications of that recession for the resource plan.	As requested, NS Power has provided an update on load impacts observed from the effects of the COVID-19 pandemic in the Draft Report (Section 4.1.5).
PRM	CA	Adjustments have been made to key inputs. RII recommends that NS Power verify the findings of the July 2019 study using the updated modeling environment and include a clearer resolution of the planning reserve margin question in the final IRP report.	NS Power updated DAFOR rates for a small number of thermal units based on discussions with stakeholders in order to use more recent and representative data; updated ELCC contributions were calculated using the RESOLVE model that was developed as part of the 2019 Capacity Study which determined the target PRM. NS Power believes these minor data updates do not invalidate the significant effort undertaken in the original study as other key inputs to determining the target PRM such as load shapes and wind shapes, target reliability criteria, and other generating unit parameters have not changed. Further, the updated PRM calculations completed on the three 2045 resource portfolios showed that the 9% UCAP PRM was sufficient and did not introduce significant excess capacity even under these very different resource portfolios; this provides further confidence that the minor assumption updates made during the IRP process will not significantly affect the target PRM calculations.
CTs	CA	In the draft action plan, NS Power indicates that it will "Develop a plan" to redevelop or replace its existing gas/oil-fueled steam units, but does not address the combustion turbine fleet. In the draft findings, NS Power suggests that its existing combustion turbine fleet is cost-effective. (16) RII recommends that the findings include a specific discussion of the economics of replacing the current CT fleet with newer CTs or another type of fast ramping generation, including a summary of the modeling evidence in support of its findings and any constraints on the options that were evaluated that may suggest a need for further analysis.	NS Power completed a detailed Resource Screening exercise prior to the start of the Initial Portfolio Study which determined that sustaining the existing CT fleet is the most economic firm capacity option for customers. This analysis is described in the Draft Report in Section 4.2.2.1; additional data was also provided to stakeholders as part of the June 26 modeling results release and the July 9 stakeholder workshop. In the Resource Screening, the existing CTs are forced to retire and the model economically replaces them with an equivalent ELCC capacity of new gas combustion turbine resources, as suggested. The 25-year NPV of the replacement scenario was $240M more expensive than the base case where the diesel units were sustained. Because the firm capacity requirements are increasing throughout the planning horizon of the IRP, both due to load growth and firm coal generation retirements, significant additional CT resources are selected in addition to sustaining the existing units. Retiring the existing fleet would further increase this PRM deficiency and require incremental CT resources, at a higher cost than sustaining the existing fleet.
Dispatch and operating reserve	CA	Day-Ahead and Real-Time schedules created by the marketing desk frequently differ substantially and persistently from the actual dispatch of the generating units. BW documented instances of high operating-reserve surpluses. (17) RII recommends that NS Power verify that its IRP model assumptions and settings reflect good operating practice with respect to these topics, update the findings section to address this topic, and share relevant detailed supporting data with stakeholders.	NS Power's PLEXOS model incorporates system operating requirements and generating unit properties and constraints which are the same as those used by the Day Ahead / Real Time scheduling group, other than where differences are required due to the different modeling software used for each purpose. In both the capacity expansion and the production cost optimizations, reserve provision is co-optimized with other variables such as generation cost and capital investment, ensuring that any reserve above minimum requirements that is available via capacity expansion or dispatched via production cost simulation is still optimal in terms of lowest total cost to customers.

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		(18) If operating reserves were maintained at the target levels (rather than the higher levels reported by Bate White, would NS Power be able to dispatch additional hydro during periods with high operating costs?	
Hydro	CA	Mersey hydro retirement evaluation and hydro system value: June 26, 2020 NS Power shared initial analysis of system value provided by hydro assets as modeled by E3. Will this modeling be finalized by NS Power using Plexos, to provide key inputs into the replacement energy cost for hydro generation used in the Company's economic analysis model? NS Power expressed the view that the redevelopment project could provide a very long-lived asset, on the order of a hundred years. If Mersey could last another 100 years with no unusual capital investments, then we would agree. But if Mersey might require another significant redevelopment investment, perhaps in 30-40 years, then that cost would not be considered by the end effects calculation and thus the analysis might not be reaching the correct conclusion. Furthermore, the end effects calculation does not take into account the likelihood that Mersey would eventually be decommissioned. (18) RII recommends that the findings include an explicit discussion of the hydro system value and the retirement analysis of Mersey in particular, including discussion of the treatment of post-2045 costs (including redevelopment and decommissioning) and the risk that either redevelopment or decommissioning could have significantly higher costs than currently estimated.	NS Power has examined the value of its existing hydro systems through both the Resource Screening phase, and via a specific analysis of the Mersey Hydro system conducted during the Final Portfolio Analysis phase. The Resource Screening was conducted over a 40-year timeframe and indicated that sustaining the existing hydro assets, with the modeled levels of investment, was economic relative to decommissioning in all cases. The anticipated long life of these hydro assets introduces added complexity and uncertainty into the analysis, as described by RII. This is noted in the evaluation of the Mersey Hydro PLEXOS sensitivity, where the ranking of scenarios changes depending on the inclusion of end effects – again pointing to the effects of the long life of hydro assets. As noted in the Findings, justification for re-investment and sustaining the Mersey system will be evaluated as part of the justification provided for a capital application. NS Power has added additional clarity on this in several sections of the IRP Draft Report including in Section 6.8.3, Finding #2d, and Roadmap item #3. NS Power will consider the suggested potential changes to replacement energy cost calculations after the conclusion of the IRP.
Rate Impact model	CA	While NS Power's estimate of incremental fixed cost revenues is a reasonable approximation, for purposes of determining approximate average rates, these incremental revenues should not be deducted from the rate estimate. The average rate should be total revenues divided by total sales. There is no reason to exclude a portion of revenues from the average rate calculation. Our first case – "Correction" – presents just the impact of removing this portion of the model.	NS Power has provided additional detail on the relative rate impact model in Section 5.3.4 of the Draft Report. It is important to note that NS Power has not provided this analysis for the purposes of determining approximate average rates, as suggested by the comment. Future rates forecasts are understood to be subject to a number of factors outside of the scope of the IRP. We have attempted to illustrate the general pressure (upward or downward) created by differing levels of electrification which requires consideration of fixed cost recovery embedded in the base year.

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Rate Impact model	CA	NS Power's use of 1994 non-fuel revenues is an appropriate starting point for the adjustment to obtain a reasonable total revenue requirement. We interpret these non-fuel revenues as including sunk costs of existing generation, T&D capital investment, and utility operating costs. Sunk costs of existing generation: These costs will depreciate and are replaced by investments that are captured within the IRP revenue requirement. Accordingly, there should be some downward adjustment. T&D capital investment: These costs will depreciate but will be replaced by investments that are not captured within the IRP revenue requirement. Under higher load scenarios, a somewhat greater level of T&D capital investment may be required, but this would be hard to estimate. Utility operating costs: These costs should remain roughly stable in nominal terms. As a sensitivity, we suggest an annual reduction of 1.5% in these revenues. The net effect of this and the IRP revenues remains an increasing revenue requirement under every scenario. See charts provided by RII.	NS Power notes that 2014 non-fuel revenues were used (correction from 1994 in the RII memo). NS Power expects that utility operating costs would remain relatively stable in real terms, but would see some escalation (due to inflation) in nominal terms; the costs in the relative rate model are treated in nominal terms. NS Power considered this factor in its base assumption that the non-modeled costs stay consistent during the planning horizon for modeling purposes.
Electrification	CA	NS Power would need to operate electrification programs at some level of cost in order to achieve the higher levels of electrification studied in the IRP, but that such programs have not yet been studied or costs developed. NS Power should include in its action plan an "order of magnitude" estimate for the level of cost that might be appropriate for its customers to bear to promote electrification. As noted in the draft findings, "Increased electricity sales due to electrification can help to reduce upward pressure on electricity rates while facilitating carbon reductions in other sectors." (22) What level of program investment in electrification would result in no net change in electricity rates for a given level of electrification? Electrification may also have significant benefits to participants – such as cost savings for other fuels – and to Nova Scotia at large – by facilitating carbon reductions across all sectors. This may be viewed as a total resource cost perspective. While this is clearly beyond the scope of the IRP, we encourage NS Power to make note that these benefits exist to avoid creating the impression that rates should be a singular basis for deciding how much electrification may be considered affordable. it would be prudent for NS Power to begin with pilot programs across the range of electrification opportunities. Some modest efforts have, in fact, already begun. Electrification should not be limited to residential, commercial, and on-road transportation. The industrial and maritime sectors also provide opportunities and should be involved early in the development of electrification programs.	Consideration of an order of magnitude for costs of electrifying to be borne by the utility was not in the scope of the IRP exercise. Consideration of the cost of potential programs relative to benefits will be important in creating an electrification strategy, which is detailed in IRP Action Item #2. NS Power notes the comments of the CA and others respecting potential to consider benefits beyond those within the scope of the IRP, as well as comments respecting areas of potential focus for development of electrification programs. NS Power will seek to engage the CA and other interested parties in design considerations for advancing this strategy as part of this Action Plan item.

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		(23) Nova Scotia Power should propose a more intentional and comprehensive electrification pilot program strategy, with the intention of setting the stage for potentially launching larger programs in three to five years.	
Evergreen process	CA	Define what an "evergreen IRP process" might look like. It is our understanding that in the past, NS Power has considered a two-year IRP cycle as potentially too frequent. The term "evergreen" suggests an even more frequent update process, with many small changes rather than a single long process.	NS Power has added detail on this to roadmap item #8; this process envisions continuous updates to the IRP model and annual reporting on Action Plan progress and Roadmap item status. As changes to the planning environment are observed via the Roadmap process, additional studies may be triggered – specific examples noted in the Draft Report include updates to DSM Avoided Cost calculations and triggering of PRM studies, for example.
Hydro assumptions	CA	ELCC for run-of-river hydro units: In our memo of August 4, RII questioned the 95% ELCC for run-of-river hydro units. It is our understanding that this ELCC is based on DAFOR only, and that operational limitations were not factored into this finding. Our most recent analysis supports a lower ELCC for run-of-river hydro units. (see chart in submission) We are struck by how much the capacity factors in peak hours differ from the 95% ELCC that NS Power estimates. Perhaps low reservoir levels reduce the capacity of the plants in some years, or limited water flow limits the number of hours for which the dispatchable units can operate. Especially if water supply is limited, these units may be held for operating reserves. (24) Can NS Power explain the discrepancy between the claimed ELCC and the actual performance of the small hydro units? (25) If these units are being held for system reserve, why is this the most economic system dispatch? Wouldn't it make sense to fully dispatch these units at peak hours and reduce the use of gas/oil steam and diesel CT dispatch? (26) Does Plexos reflect NS Power's actual operating practice?	The Capacity Study, completed as part of the pre-IRP deliverables, provides detail on the modeling of hydro in that study. Other than Wreck Cove, which was modeled as an energy-limited resource with daily energy limits (set monthly), it was determined that the other hydro assets on the NS Power system include sufficient pondage as to be equivalent to firm capacity for RECAP modeling purposes. This resulted in the assignment of a 95% ELCC to existing hydro assets. In NS Power's PLEXOS model, each of the 16 hydro systems is configured using a wide range of parameters used to shape the hydro energy to match historical production as accurately as possible. These parameters, depending on the hydro system, include: • Maximum monthly generation constraints, to reflect average historical water inflows • Minimum monthly generation constraints, to reflect limited inter-month storage at most sites • Maximum daily generation constraints, to prevent the model from "shaping" energy into peak days more than is reasonable based on system operating characteristics • Minimum hourly load constraints, to maintain riparian flows on certain systems in certain seasons • Maximum rating constraints, limiting the maximum hourly output of the systems. On smaller systems which are less dispatchable, these maximum ratings work in concert with the maximum monthly energy constraints to ensure that hydro energy is not unrealistically shaped into peak demand periods The majority of these parameters have monthly values to reflect changes in operational capabilities and practices across different seasons. Actual dispatch will depend on other operating parameters such as environmental limits, local system constraints and operating requirements, unit availability, water availability and forecast inflows, and other real-time factors. NS Power believes the IRP model accurately represents the capabilities of the NS Power hydro system and the actual dispatch patterns observed in historical data, subject to the notes above.
Wreck Cove	CA	During NS Power's long winter peaks, Wreck Cove may not be able to operate at full load for the entire peak period of a day, limiting its contribution to reliability. This limitation should be considered in combination with DAFOR in determining its ELCC and the overall system planning reserve margin.	This was considered in the original Capacity Study completed during the pre-IRP period; Wreck Cove was modeled in RECAP as an energy-limited resource with the daily energy budget varying by month based on historical data.
Coal sustaining costs	CA	NS Power updated the Plexos model with new sustaining capital cost profiles for coal units. (27) Please share those updated assumptions with stakeholders.	These estimates are provided following this matrix. NS Power will make these available to interested stakeholders. The adjustments made were as follows: • An increase in TRE-5 sustaining capital to reflect the utilization observed in the Initial Portfolio Study runs; higher operating hours and unit starts triggered additional investment requirements

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			• A decrease in Point Aconi sustaining capital to reflect the utilization observed in the Initial Portfolio Study runs; lower capacity factors observed were used to reduce the anticipated investment required. The development of separate sustaining cost trajectories for the 2030 and 2040 coal retirement scenarios was modeled in the IRP; the 2030 sustaining capital trajectories avoid any major investment (i.e. turbine/generator overhauls) in the final few years prior to retirement. These maintenance interval extensions would be managed via enhanced asset management and operating practices to reduce risks to unit reliability.
Point Aconi	CA	The audit states that “major generator work (2022) and turbine overhaul (2024) will require substantial sustaining capital investment.” This suggests above-average investment levels. The original capital cost profile assumptions for Point Aconi do not include above-average investment levels, and the higher investment years in that forecast do not match the information provided in the FAM audit. Furthermore, Point Aconi may require an expansion of its limestone mine in eight years, which could require significant additional investment that does not appear to be reflected in the IRP capital cost profile assumptions. NS Power should verify that its updated capital cost profile assumptions reflect the correct sustaining capital cost forecasts for all units, including Point Aconi. (28) Please provide the sustaining capital cost profiles and underlying assumptions in depth. The final report should include a comparison of the cost of continued operation (including fixed OM&A and sustaining capital) for each of the thermal plants.	The IRP Sustaining capital forecasts include additional investment for turbine and generator work profiled in 2021 and 2023; ongoing asset management activities and dynamic maintenance intervals may shift the timing of these investment, for example to 2022 and 2024 as identified in the RII comment. Potential long-term capital requirements for limestone supply are not included in the sustaining capital forecast. Revised sustaining capital assumptions, as updated prior to the Final Portfolio Study, will be shared with stakeholders.
Wind/inertia/FFR	CanREA	CanREA observes that NSPI focuses on constraints to wind integration, questioning whether “additional dynamic system inertia constraints can enable this level of additional wind integration” rather than acknowledging that the ability of wind generation to provide various frequency response services including fast frequency response (FFR) and primary frequency response has not been fully considered. The provision of FFR by wind generation arrests the frequency decline after a system event and can reduce requirements for synchronous inertia. CanREA understands that additional work needs to be done to determine the impact of FFR provision by wind turbines on requirements for system inertia in Nova Scotia, but as the OERA work demonstrates there is a considerable body of work demonstrating this capability and its adoption by system operators in other jurisdictions. This is a critical issue because the IRP indicates that wind generation is the most economic type of domestic renewable generation and therefore can play an important role in assisting NSPI backout coal-fired generation.	NS Power’s Action Plan includes completing further system stability studies to determine whether additional dynamic system inertia constraints, operational limits, and/or provision of alternative services like Fast Frequency Response (FFR, are required to enable higher levels of wind integration on the Nova Scotia system, particularly in advance of the commissioning of integration measures, such as the Reliability Tie. Based on stakeholder feedback, NS Power undertook two sensitivities, 2.1C.WIND-3 Low Inertia Constraint and 2.1C.WIND-4 No Inertia / No Integration to assess how the resource expansion plan would change with reduced needs for synchronous inertia. These sensitivities indicated that the wind expansion profile was not particularly sensitive to these parameters.
Wind/inertia/FFR	CanREA	Modification to Allow new wind generation to provide ramp down reserve service” (Slide 30) was a refinement that flowed from the OERA work. Modification to “Allow new wind generation to provide ramp down reserve service” (Slide 30) was a refinement that flowed from the OERA work. This is just one ancillary service that wind generation is capable of providing. By focusing on just this ancillary service NSPI failed to consider the range of ancillary services that are critical to enabling the integration of additional wind generation in Nova Scotia as demonstrated by the work performed for OERA. A ramp down service can assist with managing surplus wind generation during low load high wind output periods. However, as the OERA study indicates the critical ancillary services are frequency response	The PLEXOS LT module optimizes resource 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 and existing resources, including wind and batteries, contributes to certain modeled ancillary services. Wind resources are part of the regulation lowering service. Batteries contribute to all types of reserve including regulation (raising and lowering), 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

		services that allow NSPI to dispatch off thermal generating units and rely on the fast frequency response capability that wind generators offer. NSPI's modeling has not considered this capability and also has not considered the ability of battery energy storage projects to provide a similar service.	absence is not expected to have an impact on coal retirement decisions. However, if FFR services are found to reduce the synchronous inertia constraint, which was modeled, the economics of coal retirement with some combination of battery and wind replacement (or other) may improve (based on the FFR requirement and the resource's specific contribution). NS Power has committed to further study in this area as part of its IRP Action Plan and Roadmap.
Wind/inertia/FFR	CanREA	Continue to integrate the findings from the OERA report on how the ancillary service provision capabilities of wind, solar and battery resources (i.e., non-synchronous /inverter-based resources) can be utilized. Given the low energy costs offered by wind resources recognizing this capability is likely to reduce costs to customers while enhancing system reliability. The low cost of wind relative to other resources also creates an opportunity to operate at a reduced capacity to provide headroom to offer ancillary services (e.g., the provision of primary frequency response) under some operating conditions.	NS Power's Action Plan has committed to further system stability studies.
Wind/inertia/FFR	CanREA	Sensitivities (2.1C.WIND-3 (LOW INERTIA CONSTRAINT)) and (2.1C.WIND-4 (NO INERTIA / NO INTEGRATION)) help advance the understanding regarding the impact of inertia requirements on the amount of wind generation that can be integrated. Additional background regarding insights from these sensitivities would be helpful.	Additional insights on these sensitivities is provided in the Draft Report in Section 6.8.2.
Wind/inertia/FFR	CanREA	Re more study needed to understand understanding of increased penetration of wind: Given the recent work by OERA, CanREA encourages NSPI to update the PSC study and when doing so, to provide an opportunity for stakeholder input or alternatively to have committee of experts advise on modeling assumptions and protocols.	NS Power's IRP Action Plan includes completing further system stability studies to determine whether additional dynamic system inertia constraints, operational limits, and/or provision of alternative services like FFR, can enable higher levels of wind integration on the Nova Scotia system, particularly in advance of the availability of other resources that support wind integration such as the Reliability Tie..
Wind/inertia/FFR	CanREA	Regional Integration is critical to unlocking the potential of wind energy and CanREA encourages NSPI to accelerate this element of its Action Plan.	NS Power acknowledges these comments and has indicated in its IRP Action Plan that work on the Reliability Tie and Regional Interconnection should begin following the conclusion of the IRP process NS Power agrees.
Wind procurement	CanREA	Wind procurement strategy, "targeting 50-100 MW new installed capacity by 2025 and up to 350 MW by 2030." CanREA believes this is likely to be low given the various issues identified with modeling of the ability wind generation resources to provide frequency response services. CanREA recommends NSP provide an indicative schedule of future wind procurements based on the results of the IRP. We understand that such may need to be modified as additional information becomes available on load growth, technology costs, integration analyses. Nonetheless, establishing such a procurement schedule will signal to the development community future procurement activity that will give them the confidence to invest in project development and the local supply chain, which can de-risk future project development and reduce wind costs benefiting Nova Scotia consumers and its economy.	NS Power has provided indicative timing for procurement/development of resources which is appropriate for the purposes of establishing a near-term Action Plan. More detailed project execution strategies will be advanced within these timelines.
Solar, storage	CanREA	CanREA urges NSPI to acknowledge the potential for additional modeling and consideration of solar energy and energy storage for future iterations of integrated planning as two additional technologies that will complement the projected wind energy contributions and provide NSPI with the tools to satisfy multiple objectives supported by Nova Scotia's electricity system.	NS Power in its Roadmap has committed to refine the Action Plan and Roadmap items via an evergreen IRP process. This process will facilitate annual updates as conditions change and technology or market options develop and as Action Plan items are completed. NS Power will include a summary of updates as part of its IRP Action Plan reporting.
Preferred Resource Plan	E1	(1) The 2020 IRP Report must define a Preferred Resource Plan in line with quantitative results of the IRP modelling process, using the 25-year Revenue Requirement, adjusted for End Effects. Qualitative discussion should reflect these findings. End effects should be included when making these determinations, for the reasons summarized below.	The SDGA-compliant key scenario which minimizes the cumulative present value of the annual revenue requirement of the 25-year planning horizon (adjusted for end effects) is 2.0C (Low Electrification / Base DSM / Net Zero 2050/ Regional Integration), which will serve as the Reference Plan for calculating avoided costs of DSM.

NPV	E1	(2) The IRP results should modify the NPV revenue requirement calculation on the basis of expected carbon revenues, as they are now a key differentiator in many cases and may affect the selection of a lowest cost plan. Mid and Low DSM follow the trend that higher amounts of DSM produce incremental carbon reductions, and it is unclear why Max DSM results in higher cumulative emissions than Mid-DSM. Given a potential difference between Low DSM and Mid DSM of $630M (undiscounted) in potential carbon revenues (assuming $50 per tonne), carbon pricing merits full consideration in the IRP. Absent forecasts of carbon prices, the Federal Government's "floor" for carbon pricing is $50 per tonne in 2022. Given that Nova Scotia's inaugural cap and trade auction resulted in a settlement price of $24 per tonne, assuming levels below $24 would not seem reasonable for projections extending out 25 years. The IRP results should modify the NPV revenue requirement calculation on the basis of expected carbon revenues, as they are now a key differentiator in many cases and may affect the selection of a lowest cost plan.	In the Roadmap, NS Power has committed to tracking the ongoing development of the Nova Scotia Cap--and-Trade Program, including auction results and developing regulations. In particular, NS Power will monitor GHG market size for indications that value from incremental allowance sales (beyond the projected economic emissions reductions shown in the IRP results) can be incorporated into long-term resource planning decisions with greater certainty. Significant changes in the value of incremental GHG reductions could influence resource plan components including non-emitting generation procurement, DSM levels, and coal retirement trajectories.
T&D	E1	The methodology for quantifying T&D avoided costs from DSM is now being developed by NS Power in consultation with stakeholders. Absent quantified impacts, it is important that the final report clearly indicate the qualitative effects on T&D investments from increased or decreased levels of DSM.	The determination of the appropriate methodology for quantifying T&D Avoided Costs of DSM is being finalized in consultation with the DSMAG per E1's request. As a generation-focused modeling exercise, the IRP does not specifically evaluate optimization of T&D investments. Both the T&D Avoided Cost estimates and the IRP key scenario and sensitivity results for various levels of DSM can be used to inform future DSM procurement activities.
DSM	E1	(4) Provide more context on the results of the DSM sensitivity analyses for the electrification scenario in which they took place. The final report should include a qualitative assessment of how higher levels of DSM could provide increased ratepayer value with higher levels of electrification. Higher amounts of electrification will likely require more generation on the system, given the average load and incremental peak load outputs of the Pathways studies, and hence could climb the cost curve of available supply-side resource options. It is expected that DSM would produce results that are in line with the reference electrification scenario, but with enhanced competitiveness. Recognizing that further sensitivity analyses would be difficult to complete within the established IRP timelines, NS Power should provide more context on the results of its DSM sensitivity analyses for the electrification scenario in which they took place. The final report should include a qualitative assessment of how higher levels of DSM could provide increased ratepayer value with higher levels of electrification.	The updated Modeling Results release provides a quantification of how various levels of DSM impact the various cost measures. Additional discussion has also been provided in Section 6.8.1 of the Draft Report. These results indicate that DSM energy efficiency programs and costs consistent with a range of the "Low" to "Base" profiles are shown to be most economic relative to other options evaluated when considering both NPVRR and the relative rate impact analysis. Higher levels of DSM in resource plan sensitivities do lead to reduced capacity needs and lower emissions, but DSM potential study costs do not indicate such plan are cost-effective.
Capital risk	E1	(5) Provide an assessment of the risks associated with large capital investments such as a regional intertie and the use of non-firm imports. The 2020 IRP Report should confirm that DSM mitigates the risks associated with NS Power's plan to reduce GHG emissions within the IRP Findings and Action Plan. The added risks associated with NS Power's mitigation plans for interties and non-firm	Quantification of risks associated with capital investments outside of the scope of the IRP. NS Power undertook a quantitative analysis of reduced access to non-firm imports as requested. Please see 2.1C.IMPORT-1 and section 6.8.4 of the Draft Report for more information. IMPORT-1 for more information.

		imports should be described qualitatively (if a quantitative analysis is not possible within the schedule) as part of the IRP Draft Findings and Action Plan.	
Natural Gas pricing risk	E1	(6) Provide an assessment of risk in Natural Gas pricing assumptions within the Findings and Action Plan. In its July 10th Letter of Comment, EfficiencyOne made the following recommendations related to natural gas assumptions in the IRP: • 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 explore 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 20,000 MMBtu per day, thus allowing the model to economically select other resources other than natural gas beyond the currently contracted firm supply. These requests, as far as we understand, have not been addressed, and IRP stakeholders do not have knowledge of other stakeholder positions relative to natural gas pricing assumptions. At minimum, NS Power should provide an assessment of risk in Natural Gas pricing assumptions within the Findings and Action Plan.	When developing a plan for assumptions that would require a firm gas supply, NS Power's analysis indicated that volumes that could potentially be required would not be available from AGT. 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 this supply source is likely more economic. As reflected in the Final Assumptions document, gas supply options were developed on the basis of new natural gas units requiring firm access to a gas supply to operate reliability during the winter peaks. NS Power understands that the LNG Winter-Dawn summer would not be constrained in this regard. Similarly, the supply path from AECO (Path 3) considered firm transportation costs to supply Nova Scotia (modeled as a fixed cost adder applied to gas units in the model which select this option). In addition, NS Power undertook an additional sensitivity modeling high gas and import power prices (2.1C.PRICES-1). This optimal resource plan developed under this assumption showed only minor adjustments relative to the base case in the face of higher commodity prices, indicating that the base plan is robust to potential changes in natural gas prices.

Rate effects	E1	(7) The rate effect metrics (10-year NPVRR and estimated rates) will not contribute to achieving the general purpose of the IRP process as set out by the UARB and should receive limited consideration. The methodology described in the rate effects model is substantively different compared to the relatively more mature Rate and Bill Impact Assessment model, which has been reviewed by stakeholders and the UARB several times in Nova Scotia, and continuously improved. Further, the IRP provides the only opportunity for analysis of the long-term revenue requirement associated with the NS electricity system. This long-term view is critical in determining the lowest cost electricity system into the future, which is a complex question to answer, given the degree of changes taking place in the electricity, and broader energy, system today. The UARB spoke to this important purpose of the IRP in the 2016-2018 DSM Resource Plan decision: The general purpose of the IRP process is to identify a plan which utilizes both supply-side and demand-side resources to reliably serve the electrical requirements within Nova Scotia at the lowest long-term cost to ratepayers. The outcome of the IRP should be primarily informed by the lowest long-term cost to ratepayers. Affordability should be examined as part of the lowest cost long-term trajectory, as short-term rate impacts have many influences such as fuel costs which are subject to the vagaries of the market. Many affordability considerations are affected by near-term cost pressures and the timing of investments, matters not examined in a detailed fashion as part of the IRP.	Per the Terms of Reference, minimization of Net Present Value (NPV) is the primarily metric for evaluating future plans, in addition to other metrics of increasing importance, including magnitude and timing of electricity rate effects. Additionally, it was discussed throughout the development of the IRP modeling that due to the challenges of comparing plans with different assumptions for annual load and peak demand, relying solely on the NPV metric was insufficient. Numerous stakeholders requested the development of a rate metric for the IRP which NS Power then implemented. NS Power has presented the Rate Impact model as a simplified model to illustrate relative general upward or downward pressure on rates when comparing plans.
DSM avoided costs	E1	(8) Provide stakeholders with a proposed approach (technical and process-related) for calculating the avoided costs of capacity and energy associated with DSM. It is important that this approach quantifies avoided costs prior to the IRP Report being filed with the UARB. The determination of avoided costs must take place as part of the IRP process. While avoided costs are critical inputs to DSM planning, they are also meaningful and important to other stakeholders engaged in DSM proceedings. The technical decisions and tasks associated with the calculation of avoided costs involve: 1. The designation of at least one comparator Plan for use in the Difference in Revenue Requirements method of avoided cost generation. 2. Decisions relating to what DSM elements will be included in a given avoided cost run (if more than one). For example, will Demand Response (DR) activities be aggregated with energy efficiency (EE) as a single avoided cost run. 3. The final form of avoided cost results.	NS Power has identified plan 2.0C as the Reference Plan for the purposes of calculated avoided energy and capacity costs and has confirmed it will also provide avoided energy and capacity costs for 2.1C for additional reference. Once the final IRP Report is accepted by the UARB, confirming the selection of the Reference Plan as identified above, NS power will calculate and provide the avoided capacity and energy costs.

		These questions and decisions should be resolved as part of the IRP stakeholder engagement process. In each of the points above there are nuances and subtle changes in approach which stakeholders should generally understand. NS Power should prepare the resource plan that is to be compared with the Preferred Resource Plan through removal of DSM load modification, and allow the model to re-run resource additions in Plexos LT. The comparator plan should then be checked for reliability and operability, such that stakeholders are assured that the comparison is performed on two viable IRP cases; each viable on their own merits, and only separated by DSM. Furthermore, the 70 MW of economically selected DR should be grouped with the End Effects case or cases being examined. EfficiencyOne is interested in NS Power's and other stakeholders views on this approach, but it seems that grouping these aspects of DR will avoid the requirement for the separate generation of avoided costs for DR and EE, and will provide inherently the interaction between EE and DR, which is consistent with how the 2019 DSM Potential Study was modelled (i.e. in that DR and EE were modelled as interacting in the DSM Potential Study). Finally, the avoided cost data should be presented in the format used for the 2014 IRP. The key elements from the 2014 approach EfficiencyOne would like to see maintained on a public basis are: 1. The provision of annual avoided cost streams for both generation and energy. 2. The provision of levelized values over the planning period. 3. Key input assumptions (e.g. WACC). The IRP Action Plan should propose a technical approach and process for quantifying avoided costs, taking into account the comments provided above. This proposed approach should be reviewed with all IRP stakeholders and updated according to their feedback. The process should allow for the initial draft production of avoided costs as part of the Draft Final Report deliverable. EfficiencyOne is strongly in favor of an approach that allows for resolving avoided costs prior to an IRP-associated regulatory process, on the basis of transparency and ensuring continued participation by the IRP stakeholder group.	
Process	E1	(9) Publish responses to all stakeholder comments and questions following the submission of comments on September 18. Stakeholder comments and questions and NS Power's responses help inform all stakeholders.	NS Power has published its responses to stakeholder comments on the IRP website.
Zero emissions	EAC	While scenarios have comprehensively studied emissions reaching between 0.5 Mt and 1.4 Mt, the EAC expresses concern that no "zero" emissions scenario was studied. Zero emission cases will provide an assessment of the costs required to operate from imports, sequestered carbon emissions and renewable energy. Increased costs to the utility add value to efforts across the regional GHG reductions landscape by maximizing the impact of electrification. In addition, near-future regulatory benchmarks will dictate provincial	NS Power developed several emissions profiles in consultation with stakeholders during the Assumptions phase of the IRP, two of which incorporated trajectories designed to achieve the goals of the SDGA as currently defined. Building on this base, NS Power has focused its modeling efforts on achieving an 87%-95% reduction in GHG emissions by 2045, relative to 2005 levels. NS Power acknowledges that there remains additional potential study on how to move from a 95% reduction to a 100% reduction as the enabling technologies and policy and legislative frameworks become better defined.

		emissions to align with net-zero carbon scenario. Therefore, it would be prudent to have a future-proof plan ready for deployment.	
Transmission	EAC	Access to firm capacity imports from the Maritime provinces and Quebec would be highly beneficial to the ratepayers, as stated in draft findings statement 2. At the same time, the Reliability Tie would strengthen the province's grid further. However, it is not shown if the study explored fully replacing coal generation with building interconnection infrastructure and investing in clean firm imports. Wind will play a key role in the region's renewable portfolio, and addition of an incremental 500-800 MW capacity is a welcome move.	NS Power acknowledges the comment and the IRP Findings demonstrate that Regional Integration and the Reliability Tie offer value to electricity customers. All of the scenarios fully replace coal generation by the end of the planning horizon. The model was offered up to 615 MW of new firm import capacity, which was economically selected by 2045 in all Regional Integration scenarios. In addition, NS Power has already contracted for 153 MW of clean firm imports via the Maritime Link. This represents a transformational shift to the current generation mix. Even greater firm capacity imports could be economic in the future, as suggested; however, further analysis would be required (e.g. reliability, self sufficiency, policy certainty, etc.).
Natural Gas emissions	EAC	The North American natural gas supply has additional emissions associated with 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 emission reductions. Multiple studies indicate that fully accounting for these emissions brings the natural gas supply close to emissions intensities associated with coal combustion [reference articles]. It would greatly benefit the study if complete replacement of planned natural gas/gas turbine infrastructure with regional transmission interconnection is analyzed fully.	NS Power, through the standards for Quantification, Verification and Reporting, does not account for upstream fugitive emissions at this time. If this were to change in the future, any future planned natural gas units would be re-evaluated incorporating this requirement. NS Power will continue to monitor regulatory developments in this area and update its analysis as appropriate. NS Power has also added the exploration of low and zero carbon alternative fuels to its IRP Action Plan.
Accelerated coal phase-out	EAC	Both 2030 and 2040 coal phase-out plans will have similar rate implications for ratepayers by 2045. While the findings indicate a higher initial cost for an accelerated 2030 coal phase-out, it is worthwhile to indicate here that the province would reap immense health and economic benefits from pursuing this target. Per EAC report, Rapid decarbonization in Nova Scotia would result in the creation of around 15, 000 full-time jobs by 2030. In addition, the Federal Government's analysis indicates that an accelerated phase-out would avoid 89 premature deaths, 8,000 asthma episodes and 58,000 days of breathing difficulty for Nova Scotians, among other benefits. An accelerated phase-out of coal by 2030 would be a favorable long-term strategy for the province and its peoples.	NS Power acknowledges the comment, however, the potential health and economic benefits referenced are outside of the scope of the IRP analysis.
Regional Integration	EAC	The EAC welcomes Nova Scotia Power's notion to develop a Regional Integration Strategy. This will be highly beneficial to the province and ensure a stable and reliable grid. Once again, it would be wise to link the addition of transmission infrastructure and phase-out of fossil fuel based (including natural gas turbines) infrastructure.	NS Power agrees. The optimization model does consider both the economic opportunity to retire coal and the mandated coal retirement dates when committing to transmission investments to access low or zero-carbon replacement energy and capacity.
Electrification	EAC	Electrification of the grid will have significant impacts overall and create opportunities for other sectors, such as transportation and small-to-medium-scale industries operating on carbon intensive fuels. Draft Action Plan statement 2 and Finding 1 b) are significant and would stand to benefit from stronger advocacy: "Increased electricity sales due to electrification can help to reduce upward pressure on electricity rates while facilitating carbon reductions in other sectors"	NS Power acknowledges these statements. However, quantification of benefits outside the electricity sector was not within the scope of the IRP. NS Power has noted that electrification is a key enabler of economy-wide decarbonization in support of provincial goals and targets.

		According to the Rate impact Comparison (Select Scenarios), it is shown that High Electrification scenarios 2.2 C and 2.2 C S1 achieve lower rates as compared to select Low and Mid-Electrification scenarios. This indicates that electrifying the grid has key benefits. While, this comparison is comprehensive in terms of rate implications for ratepayers, it would be prudent to demonstrate economic benefit of switching to electric transport and electric heating through heat pump technology.	
Trenton 5, wind/battery	EAC	Decommissioning of the thermal unit at Trenton 5 is essential. As a significant number of units will reach end-of-life much earlier than 2040, earlier preparation for depreciation of these units is warranted. Accordingly, a comprehensive plan indicating the retirement scenario for all coal units is needed. Wind addition to the system is essential, but it would be necessary to consider a higher than stated "350 MW" of additional capacity. Consideration must be given to maximizing wind addition in combination with battery storage. It is clear in other jurisdictions (USA, UK, etc.) that this has worked successfully at a non-significant additional cost. Considering future examinations of upstream methane emissions from natural gas powered fast acting peakers would reveal that battery storage would be the right direction to proceed in terms of reaching carbon neutrality.	NS Power has committed to a developing a plan for the retirement and replacement of Trenton 5, targeting 2023, while securing required replacement capacity and energy. It is also committed to beginning decommissioning studies for NS Power's other coal assets and developing and executing a coal retirement plan including associated regulatory approval processes. NS Power's capacity expansion optimization software co-optimizes wind and storage. It appears that battery storage's ability to substitute for firm capacity resources is currently limited in Nova Scotia by its relatively short duration, coupled with the wider variability of wind resources (as compared to more predictable renewable sources such as solar). NS Power will continue to monitor opportunities for new storage technologies, including longer duration storage, to support retirement of its coal generation assets. NS Power welcomes more specific examples of successful wind and battery integration at non-significant cost. As discussed above, the regulatory framework for NS Power's emissions accounting does consider upstream methane emissions.
Funding to participate	EAC	The capacity of EAC and other organizations that advocate for climate mitigation, environmental concerns and energy affordability concerns, to engage in this process is greatly reduced due to the design and process of the 2020 IRP, and the lack of availability for stakeholder funding and support through the Nova Scotia UARB, through the NSPI-led process, or through the Nova Scotia Department of Energy and Mines NSPI and the Nova Scotia UARB processes will continue with ad hoc sustainability oversight until the Department of the Environment, Department of Energy and Mines, or Nova Scotia Power create an updated mandate to support climate change and environmental concerns in a way similar to the Consumer Advocate or the Small Business Advocate.	Interest group funding is a policy matter beyond the scope of NS Power's IRP exercise. NS Power thanks the EAC for its participation in this process.
Policy/Environment	Envigour (Quest / Marine Renewables)	The IRP is taking place within a rapidly changing public policy and technology environment: one that will likely evolve in unexpected directions and produce technology breakthroughs for prices and solutions not anticipated in the IRP assumptions and modelling.	NS Power will continue to track policy and technology updates; the IRP Roadmap contains many aspects of the planning environment which NS Power will monitor and which may trigger updated planning studies via the evergreen process.
Overall IRP	Envigour (Quest / Marine Renewables)	Secondly, the IRP of necessity had gaps when considering the broader energy and climate change agenda. It did not purport to be an energy IRP and thus did not evaluate the full benefits as customers shifted energy needs to the electricity system from other systems. It also did not assess the supply risks associated with dependence on imports of natural gas or environmental compliance implications of using back-up diesel. It also did not consider the opportunities for the grid from the customer purchase of batteries. And it, of course, did not assess the policy benefits of early action on decarbonization as that is the purview of the governments.	NS Power acknowledges that there are additional consumer benefits of associated with shifting energy needs to the electricity system that are not captured in the IRP modeling. The IRP scope includes modeling of the electricity system impacts of decarbonization and electrification, however, NS Power acknowledges the qualitative point made by Envigour and other interested parties about the benefits to the province more broadly. NS Power confirms that diesel generation (from the existing CT fleet) contributed to the overall modeling of NS Power's emissions compliance; the impact is not significant due to the low capacity factors of these generating units.
Stakeholder Engagement	Envigour (Quest /	We would also note that the IRP attracted more interest and participation from stakeholders than usual with peak on-line call registration in the range of 170. In particular,	NS Power is pleased with and appreciates the level of stakeholder engagement and believes this has improved the IRP process throughout.

	Marine Renewables)	Municipalities were interested in how the IRP conclusions and implementations align with their policy and program goals.	
Roadmap/Action Plan	Envigour (Quest / Marine Renewables)	Finally, we observe that the measures under the actions and roadmap to ensure the plan is evergreen is not spelled out. It may be prudent to offer more clarity on that process using principles of inclusion, science-based conclusions, and a broad range of expert opinions and thinking tested for practicability in the Nova Scotia policy/regulatory environment.	NS Power has provided additional detail on the evergreen process as part of IRP Roadmap item #8; this process will facilitate annual updates on Action Plan progress/completion and Roadmap items as conditions change and technology or market options develop. NS Power will include a summary of updates as part of its IRP Action Plan reporting.
Future Steps	Envigour (Quest / Marine Renewables)	To enable a transparent and inclusive process, we suggest an annual or semi-annual extended workshop on climate change and clean technology policies and programs informed by expert views on trends for electricity technologies and costs.	This type of workshop would be outside the scope of the IRP process; NS Power observes and understands the increasing desire for stakeholder engagement on matters related to energy planning and looks for opportunities to participate where appropriate.
Roadmap/Action Plan	Envigour (Quest / Marine Renewables)	From this, we suggest that the final Roadmap and Action Plan reference the need for a regular and inclusive informative process to examine changes in the technologies, business models and best practices, and the policies and program initiatives that could impact the IRP assumptions and scenarios.	The Roadmap will address the longer-term needs for process updates; the action plan is a near-term document setting out immediate steps.
Natural Gas (more)	Heritage Gas	The Draft Findings, Action Plan and Roadmap results distributed to interested stakeholders on September 2, 2020 and presented on September 10, 2020 further indicate a required need and reliance for natural gas in the province over the next 25-year period. The results presented show that natural gas will provide electrical grid reliability, critical ancillary services, an economic energy source, and a lower carbon energy source to meet the province's environmental goals.	NS Power agrees that natural gas continues to be a source of energy and firm capacity during the IRP planning horizon.
CTs (additional firm capacity)	Heritage Gas	in Draft Finding 3(a), NSPI discusses the requirement to add significant new CT capacity. As previously mentioned, Heritage Gas has natural gas distribution infrastructure in very close proximity to the four diesel-fueled Burnside CTs. The conversion or replacement of the now 45-year old CTs provides an opportunity to both address the reliability issues with the existing CTs and address the need for additional CT capacity. The replacement of the Burnside CTs should be strongly considered. Heritage Gas recommends that a specific Action Item be identified in the final report to address the reliability issues identified by Bates White and the cost-effective utilization of existing infrastructure to meet the needs for additional CT capacity.	NS Power has made investments into the diesel CT fleet to resolve reliability issues, including the oil cooling systems mentioned in Heritage's comments. NS Power's IRP analysis has conclusively shown that sustaining the existing Diesel CT fleet is the most economic firm capacity option for customers. The gas CT capacity requirements noted by Heritage are incremental capacity in addition to the existing diesel CT fleet, which is sustained in the IRP. The existing site would need to be evaluated in the context for suitability. Many considerations for new and/or replacement gas generating units will be considered as part of the work under IRP Action Item #3c, "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."
Coal to Gas conversion	Heritage Gas	In the Modelling Results, the long-term resource changes emphasize additional natural gas resources including coal-to-gas conversions. The Draft Finding 3(c) shows natural gas as a key requirement of the developing electricity system in both the near and long term. Draft Roadmap item 1 discusses the need for "advance engineering study work on coal to gas conversions at Trenton and Point Tupper Generating Stations". The Action Plan should reflect a timeline of completion of this study and scope of the work included in the coal-to-gas conversion scenario. Heritage Gas also notes that an increase of this size in natural gas consumption in the region requires long-term natural gas transportation commitment planning, which should also be reflected in the Action Plan.	NS Power has provided several natural gas pricing options to the model, some of which incorporate firm long-term agreements while others rely on (generally higher) spot market pricing for lower capacity factor units such as the coal-to-gas conversions as modeled.
Electrification	Heritage Gas	This IRP is unique in contrast to previous IRP's in that very significant investments will be required in NSPI's transmission and distribution assets. This investment is driven by potential increased electrification of end-use energy, such as transportation and building heat, and the need to meet the lower environmental targets specified in the Sustainable	NS Power acknowledges that increasing levels of economy-wide electrification could have impacts on the requirements of the Transmission and Distribution (T&D) systems, and IRP Action Plan item #2c indicates that these impacts will continue to be monitored and addressed during the IRP Action Plan period. In addition, Roadmap Item #7 will monitor ongoing electrification-related load growth in Nova Scotia and will allow NS Power to identify when the load on the system starts to trend toward a "Mid" level of

		Development Goals Act ("SDGA"). Significant investment in T&D is also expected to arise from the large potential increases in peak energy demand.	electrification from the current "Base" level. An observed transition will trigger additional work to quantify T&D impacts based on early observed system impacts.
Avoided T&D Costs	Heritage Gas	Heritage Gas understands that there is an ongoing process through DSM Matter No. M09471, to agree on the avoided T&D costs of Demand Side Management ("DSM"). This matter considers only a fraction of total T&D costs and so, it would be prudent to discuss these findings with the larger stakeholder group and also include a continued study of T&D costs in the context of the increasing electrical load envisioned in the IRP.	NS Power is currently working with the DSMAG to update the current methodology used for calculating Avoided T&D Costs of DSM. The current draft methodology considers all T&D capital expenditures related to load growth, and so should capture the costs that might be incurred in expanding the T&D system to support electrification load.
Emissions (Low Carbon)	Heritage Gas	Electrification in certain sectors of the economy will assist in moving Nova Scotia toward a lower carbon economy. However, electrification alone will not substantially reduce the GHG emissions in the province in order to meet the SDGA net-zero 2050 target. // Recently the Offshore Energy Research Association ("OERA"), Liberty Utilities, Heritage Gas, and the provincial Department of Energy & Mines engaged Zen Energy Solutions to determine the future potential uses of hydrogen in Nova Scotia. Hydrogen is increasingly seen as imperative in meeting the net-zero goals established in the Sustainable SDGA and NSPI should specifically identify hydrogen within the action plan and roadmap.	The Pathways study released to stakeholders at the start of the IRP showed that electrification was a significant contributor to the overall economy-wide decarbonization. NS Power will continue to monitor new technologies that can contribute to firm capacity and energy production for the Nova Scotia system, and has included consideration for fuel flexibility and low/zero carbon fuels, such as hydrogen, in Action Plan item #3c which will 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.
Action Plan	Heritage Gas	• The Action Plan should specially consider the replacement of the liquid-fueled CTs in Burnside with gas-fired CTs as a cost-effective means to reliably meet the incremental capacity requirements identified in the IRP. • The Action Plan should identify the specific timeline and scope of the engineering study regarding coal-to-gas conversions. The assumptions on long-term natural gas transportation contracts should also be included within this action item. • A timetable should be established for estimating the incremental T&D costs associated with the various electrification scenarios. The IRP stakeholders should be kept fully informed as these cost estimates are developed • The Action Plan and Roadmap should specifically identify hydrogen as a means to assist the province in meeting the GHG reduction targets established in the SDGA.	NS Power's IRP analysis has demonstrated that sustaining the existing Diesel CT fleet is the most economic firm capacity option for customers. NS Power's Findings and Action Plan have identified that additional CT capacity will be a key source of firm capacity in all the optimal resource plans modeled, enabling coal retirements and providing Ancillary Grid Services. NS Power is currently working with the DSMAG to update the current methodology used for calculating Avoided T&D Costs of DSM. The current draft methodology considers all T&D capital expenditures related to load growth, and so should capture the costs that might be incurred in expanding the T&D system to support electrification load. NS Power will continue to monitor new technologies that can contribute to firm capacity and energy production for the Nova Scotia system, and has included consideration for fuel flexibility and low/zero carbon fuels, such as hydrogen, in Action Plan item #3c which will 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.
General	Heritage Gas	The assumptions and scenario modelling used in this IRP reflect the need for continued monitoring of the development of the electric and broader energy sectors in the Province. Unlike past IRP's this IRP suggests some possible fundamental differences in the future electric sector in Nova Scotia. These fundamental changes include for the first time a general future separation of capacity from energy, a potential focus on electricity growth versus general DSM (still dependent on full costing of such an approach) with a continued requirement for focused DSM and Demand Response on peak, the potential requirement for significant new regional transmission to allow both increased firm and non-firm energy imports, the requirement for more fast acting generation to support increased renewable development and provide peak response capability, and the need to significantly monitor over time the take up of new technologies such as electric vehicles, distributed generation, battery or other storage options, etc. Of these changes, one of the most significant is the availability of significant volumes of firm dispatchable imports that are incremental to those	Firm Imports via a Regional Interconnection have been economically selected by the model in all the Regional Integration cases where that supply option was available; this supply option was not forced or assumed into any of the Regional Integration scenarios or sensitivities. NS Power has identified as an Action Plan item the development of a Regional Integration Strategy following the conclusion of the IRP, and this will update the UARB and interested parties on a regular basis as described in Roadmap item #8.

		available through the Maritime Link. To meet the lower carbon intensities for electrical generation in the low to high electrification scenarios highlighted in the Draft Findings[11], the study assumes that the Nova Scotia electrical grid will need to rely on between 435 and 615 MW of firm dispatchable energy and the required investment in NS-NB tie line to accommodate this energy. NSPI has not provided any of the key assumptions associated with these imports including costs or carbon intensity and they have indicated that there are no commercial agreements in place to underpin the incremental imports. As such, it is important that all stakeholders are kept apprised over the next number of years of the data collection, study results and future opportunities that might present themselves, so that the electricity sector in Nova Scotia works in concert with other sources of energy and opportunities in the wider energy sector in the Province, to ensure a sustainable competitive energy sector which will benefit all stakeholders. In consideration of these potential fundamental changes all parties will need to closely monitor developments in the electric and broader energy sectors to ensure Nova Scotian residents and business have access to competitive alternative energy supplies and to cost effectively meet the goals of the Province.	
Supply-side (Compressed Air Storage)	JFS Hydrostor	JFS Hydrostor's process, compressing air and storing electricity is considered a proven technology and ready to deploy. As you know, we … continue to be frustrated or disappointed to learn that long duration energy storage technology is not and has not been given its due in the preferred portfolio solution into the future. … Nova Scotia Power has instead opted for a portfolio that calls for new transmission and fossil fuel assets to meet balancing and peaking requirements. • Hydrostor is a cost-effective non-wire alternative solution for transmission that is easier to permit and more cost effective than large transmission projects or pumped-hydro projects. • As a clean source of synchronous generation capacity with similar system benefits and operating characteristics as coal that can be used to advance coal retirements and be located on or near the sites of former coal plants while retaining many of the plant's employee (this concept is now being considered in other areas of North America). • Can be used to balance intermittent resources such as wind and solar or instead of natural gas fired plants, as a peaking asset.	NS Power has offered compressed air energy storage (CAES) technology and other storage technologies to the IRP model, but they have not been selected by the model as part of the optimal resource strategies for the key scenarios and sensitivities studied in the IRP. NS Power notes that optimal portfolios are an output of the capacity expansion model and are not produced manually by NS Power.
Supply-side (compressed air storage) assumptions	JFS Hydrostor	Based on our review of Nova Scotia Power's IRP assumptions, we believe that ACAES'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 per 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.	NS Power's IRP model treats CAES and battery storage as independent resource options available to the model, each with its own properties including capital cost, ongoing costs, firm and nameplate capacity, available storage duration, round trip efficiency, and other parameters necessary to model the resource. The model evaluates all these parameters together as part of generating an optimal resource plan, and does not strictly compare prices on a $/kW basis as appears to be noted in the comment. NS Power notes that overall, storage quantities selected in the key scenarios are rather modest and interprets this as being related to a combination of factors including cost of storage resources, storage ELCC factor (which has a more significant impact for short duration storage), the increased variability of

		Our concern is that this was not an apples-to-apples comparison as it accounts for the additional cost of a longer duration facility but ignores the additional value such a system provides. Additionally, by choosing to use the costs for a 200 MW system, this did not account for the significant economies of scale that come with larger sized A-CAES facilities. If you consider a 500 MW facility with a 4-hour duration, the cost works out to an average of US$1125/kW1. We believe that this is a much fairer comparison to a 4-hour lithium-Ion system for the short duration market. However, A-CAES's cost advantage is most apparent in the long-duration market where it 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. To illustrate this point, we compared the bid prices that we recently submitted for a 300 MW 6 hour and 12 hour facility to a utility in California to what an equivalent lithium system would cost based on prices provided by Lazard's Levelized Cost of Storage Analysis 5.0. For the 6-hour system we found that lithium ion prices would have to drop 7%-50% from 2019 in order to achieve cost parity. Whereas, for the 12-hour facility we found that lithium ion would have to decrease their cost by a further 41%-70% in order to achieve cost parity.	wind integration vs. more predictable solar generation cycles seen in other jurisdictions (i.e. several consecutive days of very limited wind duration), and availability of competitive options such as firm imports and CTs that can also support variable renewable generation and provide Ancillary Grid Services.
Wind (general)	Natural Forces (Andrew Cooke)	Natural Forces is active across the country and is actively building out wind project currently and over the next few years, so the prices and energy numbers from today's and tomorrow's wind projects are well known to us. Two comments: • the price per MW installed is much closer to the 1.5 million per MW; and • the capacity factors are closer to mid 40% than the number stated by NSPI. This does lead us to believe that more wind now is the answer, and that the way to unlock these saving for the rate payers and the utility is to look to other jurisdictions that have large wind resources in use and adopt some of their operating procedures in order to keep the system stable and allow for more wind on the system.	NS Power modeled a range of prices to understand the sensitivity of the model to this variable; this has been incorporated into the final report. NS Power's capacity factor assumptions were based on publicly available CanWEA data (see Supply Options Study and IRP Assumptions for more details). NS Power has identified the need for additional stability studies regarding operating limits into its IRP Action Plan as a component of Action Item 3d.
Wind (general)	Natural Forces (Andrew Cooke)	A major transformation of the existing generation resource base is required. As Nova Scotia Power has remarked, significant efforts are required to achieve the level of carbon emissions reductions in line with Nova Scotia's Sustainable Development Goals Act. A major transformation of the existing generation resource base is required, including the integration of significantly higher volumes of intermittent, non-synchronous renewable energy resources. However similar transitions have been successfully achieved in other jurisdictions. It is helpful that that there is a significant degree of commonality in the main "building blocks" selected in each of the scenarios, those being (for the main part): wind capacity; gas-fired CTs; the 2nd AC intertie, and regional integration. The scenarios differ in the order and rate at which the new resources are deployed, and the rate at which certain existing resources (principally the coal-fired units) are retired. As can be observed, several scenarios have approximately 200 MW of new wind capacity coming on by 2025 to 2027, and amounts ranging from 400 to 800 MW by 2029/2030. The higher wind capacities are generally arising in the cases based on higher electrification, as might be expected.	NS Power agrees that there is a high degree of commonality among the various optimal resource plans studied under both the key scenarios and sensitivities; this commonality has informed the IRP Action Plan. NS Power's wording in Action Plan item 3d, "Initiate a wind procurement strategy, targeting 50-100 MW new installed capacity by 2025 and up to 350 MW by 2030", is built around the ranges found in the optimal resource plans of several key scenarios in those years, including plans 2.0C (0 MW 2026 / 400 MW 2030) and 2.1C (112 MW 2026 / 362 MW 2030). As noted, higher levels of electrification and earlier mandated coal retirement dates are generally correlated with higher levels of installed wind generation in any given year. NS Power's IRP Roadmap contains items to monitor regarding both trends so that the resource strategy can shift as required.

		NSP has identified that higher electrification is beneficial to reducing electricity rates (and it is presumably also beneficial to achievement of Nova Scotia's broader emissions policy goals). In light of the above, NSP's proposed/draft action plan item 3(c) viz: "Initiate a wind procurement strategy, targeting 0-100 MW new installed capacity by 2025 and up to 350 MW by 2030" seems unduly limiting, particularly as regards the implied "upper limit" of 350 MW by 2030. Several scenarios, including those identified as resulting in lower electricity rates, have substantially higher wind volumes.	
Wind (cost) DERs Regional integration	Natural Forces (Andrew Cooke)	Another key point to note is that many scenarios are introducing some level of additional wind capacity, even with the imposed requirement that wind installed capacity of greater than 700 MW must be accompanied by either batteries/synch comps, or the second AC intertie. This has the effect of imposing an entirely unnecessary and inappropriate additional capital cost on wind (i.e. the associated capital cost of the batteries/synch comps), which is very likely reducing the level of wind being installed in many of these cases. It is difficult to be precise about the level of additional costs being imposed through this requirement as the batteries will bring some other benefits (such as energy arbitrage) which will act to off-set the added capital costs. However approximations suggest it may be adding in the region of 5 to 10% to the effective cost of additional wind capacity. The continued insistence on the part of NSP to adhere to this position is rather baffling. The precise extent to which wind capacity is being "held back" due to this approach is difficult to quantify (though of course it could be assessed by disassociating the requirement for batteries/synch comps in the modeling). However I believe it can be stated with certainty that the NSP approach will inevitably result in some level of higher costs to electricity consumers (as compared to the standard approach adopted in other power systems integrating comparatively high levels of intermittent and non-synchronous renewable generation). This is discussed further in section 5.	NS Power has modeled numerous sensitivities on wind integration assumptions, including a boundary case where the integration requirements (and other system requirements such as constraints on synchronized inertia) were removed from the model to help understand behaviour under these circumstances. NS power also notes that many key scenarios, including 2.0A, 2.0C, 2.1A, 2.2A, and 2.2C do not fully subscribe the 100 MW of wind that the model was able to add without the integration requirements referenced (Reliability Tie or batteries and synchronous condensers); this suggests that regardless of integration requirements, the modeled wind integration requirements are not significantly affecting the resource plan in the near term (i.e. within the five-year IRP Action Plan timeframe).
Electrification	Natural Forces (Andrew Cooke)	Higher electrification scenarios are beneficial to electricity consumers through lower rates, and will also support cost-effective achievement of broader emissions policy objectives. NSP has identified that higher electrification is beneficial to reducing electricity rates. It is presumably also beneficial to achievement of Nova Scotia's broader emissions policy goals, as it supports decarbonisation of other sectors (transport, heat). It is recommended that this point is emphasised strongly in the findings and is considered in NSP's action plan.	NS Power agrees that electrification as modeled is beneficial both in terms of customer relative rate impact and ability to integrate additional variable renewable generation. NS Power has included the development of an Electrification Strategy as a core component of its IRP Action Plan (Action Plan Item 2).
Wind (additional sensitivities)	Natural Forces (Andrew Cooke)	Sensitivities with lower wind costs profoundly affect the resource plan and need significant further analysis. The sensitivities with lower wind costs have a profound effect on the resource build-out plan. Much larger quantities of wind capacity (c. 600 MW) are being added by 2023 to 2025. These scenarios also have the benefit of lower CO_2 emissions than comparative scenarios. As these scenarios are based on very credible wind cost projections (and disassociation of battery costs would also contribute to lowering the effective cost of wind) it is of critical importance that further analysis is undertaken in this area, including gaining an understanding of the price point(s) at which transition occurs. [Refer section 2]	NS Power has incorporated elements and learnings of the Low Wind Price sensitivity (2.1C-WIND-1) into the IRP Final Report and Action Plan. In particular, NS Power has noted in IRP Roadmap Item #5 that Nova Scotia-based market information will inform whether market pricing is more consistent with the "Base" or "Low" trajectories for wind.

		The sensitivity cases undertaken with lower wind (and battery) costs[1] are or particular interest, and result in a fundamentally different build-out plan. As can be seen, the lower wind costs have a profound effect on the resource build out plan, even compared to the "original" scenarios with higher wind build-out (such as Case 3.1C). Much larger quantities of wind capacity (c. 600 MW) are being added by 2025, and even earlier in Case "2.1C WIND-2" which also has lower battery costs. Given that this has such a fundamental impact, coupled with the fact that lower wind costs are a highly credible scenario, further investigation of this scenario is critical. At present it tells us that changing the wind costs from the "Base Case Wind Cost" ($2,100/kW) to the "Low Wind Cost" ($1,500/kW) has a major impact on the timing of the deployment of additional wind capacity. However it does not tell us at what wind cost does this major change occur3. If it happens (in whole or in part) at a higher wind cost (somewhere between $2,100 and $1,500), it further increases the confidence level that the benefits of the "lower wind cost" cases are achievable. Once more, the unnecessary association of the battery costs with increased wind (until the advent of the 2nd AC intertie) is also an important consideration. The reduction in wind costs required to create the change to a more rapid wind build-out plan, could be arrived at through a combination of lower wind capital costs and savings from disassociating the battery requirements. // In summary, the findings from the "low wind cost" scenarios are much too significant to ignore, and it is of critical importance that further analysis is undertaken to understand the price point(s) at which transition occurs. It is also strongly recommended that the association of battery and synch comp costs with additional wind capacity, is discontinued for these (as well as other) scenarios.	
Wind	Natural Forces (Andrew Cooke)	The suggested build out rate for wind in NSP's initial draft action plan, is understated. NSP's proposed/draft action plan item 3(c) states: "Initiate a wind procurement strategy, targeting 0-100 MW new installed capacity by 2025 and up to 350 MW by 2030". This is unduly limiting at this stage, particularly as regards the implied cap of 350 MW by 2030. Even before consideration of the "low wind cost" sensitivities, several scenarios, including those identified as resulting in lower electricity rates, have substantially higher wind volumes.	Please see the response above.
Emissions and CO_2 monetization	Natural Forces (Andrew Cooke)	CO2 levels vary widely between scenarios. There is a wide variation in the CO2 levels (both annual and cumulative) between the different scenarios. Even if not directly monetizable, there is a definite value in lower CO2 emissions: a) as a risk mitigation strategy against upward pressure on emissions levels from additional demand growth, or further downward revisions in emission targets; and,	NS Power has provided annual emissions results in both graphical and tabular (electronic) format, as well as summary metrics of total emissions over two different time periods, for all key scenarios and all sensitivities modeled. NS Power has not monetized incremental reductions in GHG emissions in the IRP model; and additional discussion on this topic is provided in the IRP Final Report. NS Power notes that many key scenarios have economically emitted below the modeled hard caps, and agrees this does provide a buffer against load growth or changes in emissions limits.

		b) as can be observed from experience in other jurisdictions, lower carbon intensity of the electricity sector (lower CO2/MWh) promotes electrification of other sectors (heat, transport), which is identified as lowering electricity rates and will also contribute to achievement of broader emissions policy objectives. The differences in CO2 levels should be highlighted clearly in the results, to that individual stakeholders and stakeholder groups can consider the impacts. [Refer section 3] There are also benefits (not currently monetised) from reduced CO2 submissions in the cases with higher wind build-out. This is discussed further in section 4. // To the best of my knowledge, the benefits of a lower level of CO2 emissions is nor currently monetised in the IRP modelling approach. This is of course dependent on the emissions framework applicable to the jurisdiction. In Europe for example, the approach would be to directly monetise the benefit of a lower CO2 emission level. Even if that is not appropriate within the current framework applicable in Nova Scotia, it is suggested that the differentiation between the scenarios in terms of CO2 levels is a significant factor which should be highlighted to a greater extent. Also even if not directly monetizable, there is a definite value in lower CO2 scenarios as a risk mitigation strategy: • In a scenario where CO2 is “only just” below the required limit, then there is a risk that in the event of, say, higher demand growth and/or greater levels of electrification, that the limits would then be breached (or that meeting them – if even possible – would involve suboptimal and expensive strategies). • If emissions limits are revised downwards, the additional actions and costs required to achieve them (starting from a lower CO2 base), are likely to be much less significant. It can also be observed from experience in other jurisdictions, that the lower the carbon intensity (CO2/MWh) of the electricity sector, the more it becomes a “strategy of choice” for other sectors (transport, heat) to achieve their emissions-reduction objectives. Aside from assisting in achievement of Nova Scotia’s emissions policy objectives more generally, lower CO2 intensity is likely to promote higher electrification, which is identified by NSP as contributing to lower electricity rates.	NS Power agrees that many customers are interested in lower emission electricity; this transformation has been a foundational aspect of this IRP, and meeting this customer demand is likely to support incremental electrification which the IRP has shown has a positive impact on electricity rates.
Risk Assessment	Natural Forces (Andrew Cooke)	Consideration of Risk. There is merit in giving further consideration to risk assessment, as a tool for identifying scenarios and/or actions which show strong performance (in terms of low cost) across a range of future sensitivities. It is likely that scenarios with higher renewables and/or lower CO2 emissions would tend to be more favourable under such an examination, as they are “proofed”, to a considerable extent, against potential variables such as high fossil fuel costs, high emission costs (or tightening of emissions limits), or higher demand growth/electrification (potentially resulting in breaches of emissions limits). It is recommended that this type of analysis is considered further. [Refer section 4]	NS Power has taken the approach of developing an IRP Action Plan and Roadmap based on the outputs of multiple low-cost scenarios (e.g. 2.0C, 2.1C, 3.1C, and informed by 2.1C.WIND-1); these scenarios are selected on the basis of their lower NPV Revenue Requirement (NPVRR) and relative rate impact compared to other scenarios and together cover multiple assumptions for electrification level, coal retirement date, emissions trajectory, and wind pricing.

		A common approach is also to look for scenarios and/or actions which are "low regret" scenarios, i.e. a scenario which is not necessarily the "lowest cost" in a given set of circumstances, but shows strong performance (in terms of low cost) across a range of future sensitivities. It could be likely that scenarios with higher renewables and/or low CO2 emissions would tend to be more favourable under such an examination, as they are "proofed", to a considerable extent, against potential variables such as high fossil fuel costs, high emission costs (or tightening of emissions limits), or higher demand growth/electrification (potentially causing breaches of emissions limits). It is recommended that this type of analysis is considered further.	
Stakeholder Engagement	PHP	PHP is appreciative of NS Power's efforts to actively and fully engage all stakeholders as part of its long-term planning processes. The IRP results clearly demonstrate the significant changes to the Nova Scotia electricity system that are expected to occur over the next 25 years. In this regard, the Draft Action Plan and Roadmap identify the need to initiate and develop several new strategies, plans, and programs in the near term. PHP supports this approach, as well as NS Power's plans to continuously refine the Findings and Action Plan items via an evergreen IRP process, on the basis that NS Power will continue to hold regular and transparent engagement sessions. Such sessions will ensure stakeholders have the opportunity to provide valuable feedback that can be incorporated in the transition of the electricity system, particularly as circumstances evolve and updated information becomes available.	NS Power appreciates the comment and agrees that stakeholder interaction during the IRP process has been valuable in developing the Findings, Action Plan, and Roadmap items presented in the Draft Report. As part of the continuous refinement of the Findings and Action Plan items via an evergreen IRP process, NS Power has committed to providing annual updates on the status of various Action Plan and Roadmap items. These updates would be shared with interested stakeholders and NS Power may engage stakeholders on items as appropriate.
Flexibility	PHP	In contrast to prior IRPs (which specifically sought to develop a long-term "Preferred Resource Plan" from among a set of candidate resource plans), the 2020 IRP results provide a comparison of various resource portfolios across a range of electrification scenarios. Maintaining maximum flexibility in the near term is needed to ensure that NS Power's long-term strategy best accommodates the current uncertainty regarding future electric load growth in the Province. Preserving such flexibility will also enable NS Power to consider any subsequent changes in technology and/or government policy, as well as the results of ongoing costing analysis of generation and transmission options. These items will impact the economics of important long-term decisions regarding the timing and extent of (i) coal retirements, (ii) new capacity additions, and (iii) new renewable energy generation. Further, the significant potential investments in regional integration will require careful and strategic consideration and coordination with other jurisdictions in the region to ensure Nova Scotia stakeholders receive the intended benefits.	NS Power agrees and acknowledges the importance of maintaining flexibility. NS Power acknowledges the specific need for direct discussions and engagement with neighbouring jurisdictions as part of the development of the Regional Integration strategy contemplated in the IRP Action Plan and has added wording to this effect in the Draft Report.
Rate Impact	PHP	In its Updated Modeling Results and Draft Findings, NS Power developed a rate impact calculation using IRP partial revenue requirements for each scenario to illustrate the long-term effects of various levels of electrification. PHP believes that consideration of the potential overall impacts on future rates should remain a central consideration of NS Power's long-term strategy and planning processes. The cost of electricity, as well as the stability and predictability of electricity rates, remain critical issues for all stakeholders, particularly industrial customers that compete globally and require ongoing capital investment.	The relative rate impact model that has been developed has been a valuable addition to this IRP, particularly when used to examine impacts over different timeframes (e.g. the 10-year and 25-year average annual impact metrics presented in the IRP Modeling Results). This approach has also shown value by allowing the comparison of scenarios that vary in terms of electrification levels and/or the presence of non-utility DER resources not otherwise captured in NPV calculations.
Demand Response	PHP	As parties are aware, earlier this year, the Board approved NS Power's Application for approval of the Extra Large Industrial Active Demand Control Tariff. This innovative rate structure, developed following extensive collaboration with the utility, provides NS Power	NS Power agrees with the comment that firm capacity will continue to be a key requirement of the Nova Scotia system and has incorporated this into IRP Finding #3.

		with a new demand response service that allows the utility to better operate its electricity system for the benefit of all customers. The 2020 IRP results indicate that firm capacity resources will continue to be a key requirement of the developing NS Power system in both the near and long term, demonstrating the inherent value in demand response-type approaches going forward. Continuing to pursue deeper levels of collaboration and innovative solutions, whether through rate design approaches or otherwise, will help ensure that the transition to Nova Scotia's electricity future can be achieved in an environmentally and economically sustainable manner for NS Power and its customers.	NS Power also agrees that the IRP has shown that DR resources, as modeled in the IRP, have economic value to the system and to electricity customers and has integrated this into Finding #3e and Action Plan item #4.
Findings / Results	SBA / Daymark	NSP has conducted extensive modeling and analysis in support of the IRP analysis. However, in the presentation of the draft findings, it was not always clear precisely how each finding was supported by the modeling analysis. In the full IRP, we encourage NSP to support the findings with specific references to model runs and related analyses.	NS Power agrees with this comment and has integrated this into the presentation of Findings in the IRP Final Report.
System Inertia	SBA / Daymark	The draft Finding #2 acknowledges this, noting that "Further work is required to assess system stability at these significant penetrations and determine whether additional dynamic system inertia constraints can enable this level of additional wind integration on the Nova Scotia system" (Slide 47). The draft Roadmap item #2 also states that NSP will "Complete detailed system stability studies…while considering higher quantities of installed wind capacity…" (Slide 60). The modeling of the inertia requirement has supported certain resource decisions, in particular the addition of the Reliability Tie which is assumed to provide all the system inertia needed by the NSP system. However, this conclusion requires some further investigation. Additionally, NSP has previously noted that it has not evaluated the possibility that wind projects could provide fast frequency response, which is a method of addressing system inertia concerns used in other regions. We recommend that as part of the IRP, NSP should provide a concrete plan for conducting the additional analyses needed to assess the system needs, and the ability of different resources to address these needs (conventional generators, the Reliability Tie, Maritime Link, advanced wind turbines, and load resources). While the draft analysis indicates that the assumed system inertia requirement is not binding for several years, it is possible that cost declines for wind capacity or other factors could advance the timeline for wind development, hastening the need for a solution to the reliability need.	NS Power has identified future work related to wind stability studies at higher penetrations in the Findings and this is discussed in the Action Plan and Roadmap. With regard to system inertia, NS Power notes that it added a sensitivity under which the Reliability Tie provided only half the required synchronized inertia and this resource was still selected by the model; the optimal resource plan was largely unchanged from the base case. NS Power has not expressly modeled a FFR requirement, which is a service that is separate from synchronized inertia (it performs a similar function but is slower acting that synchronized inertia; see for example Michael Milligan, "Sources of grid reliability services," The Electricity Journal Volume 31 Issue 9, November 2018). NS Power understands that wind resources can provide various levels of FFR services. NS Power has stated that FFR is not a constraint in its capacity expansion or dispatch models, as transient system stability studies assess FFR in timescales of seconds (or less). However, NS Power agrees that if FFR services on certain generators (e.g. wind) are found to reduce the synchronous inertia constraint, the economics of building more variable renewable energy could improve (absolute additions and/or timing). NS Power has committed to such study. NS Power has incorporated the development and execution of this plan into the IRP Action Plan phase.
Regional Integration / Reliability Tie	SBA / Daymark	Most IRP scenarios include the selection of the Reliability Tie and Regional Integration as part of the optimal portfolio. Implementing this strategy will require significant coordination with New Brunswick and availability of supply. Given the primary role of the transmission solutions in NSP's plan for a reliable and economic supply portfolio, the Company should prepare a specific timeline and plan for the steps required in Action Plan Item #1 to ensure that this is a feasible solution to deliver the benefits assumed in the IRP.	NS Power agrees with this and has included language respecting the need for coordination and collaboration with neighbouring jurisdictions as part of its re-worded Action Plan item #1c in the Draft Report; this item also speaks to evaluations of supply availability (and additionally, security of supply, emissions intensity, and dispatch flexibility). Project timelines within the overall Action Plan timelines will be developed as part of the execution of the Action Plan.
Rate Impact	SBA / Daymark	We appreciate NSP developing the rate impact model to help assess the implications of various portfolios for customers (Slide 31). We believe this provides important information in the consideration of various strategies. The summary of results provided in the draft Findings presentation (Slide 43) contain interesting conclusions, particularly related to the rate impact under high electrification scenarios. This slide was accompanied with important discussion during the stakeholder session which provided context on rate trends.	NS Power agrees that this analysis has been instructive and has added value to the IRP process and findings. NS Power has added additional discussion and support to this finding (1b) in the Draft Report. The Draft Report also includes details on the rate modeling approach in Section 5.3.4 and more discussion of the results of the relative rate analysis in Section 6.5.

		We recommend that NSP provide sufficient context in the IRP to communicate the implications of the rate impact analysis on customers, specifically as it relates to Finding 1b ("Increased electricity sales due to electrification can help to reduce upward pressure on electricity rates while facilitating carbon reductions in other sectors.")	
Electrification	SBA / Daymark	Increased electrification and advanced technology can provide enhanced capabilities to NSP to manage some of the challenges introduced by higher penetrations of non-dispatchable resources. Action Plan Item #2c calls for a data collection program related to electrification. We support this program, and encourage NSP to pursue it rapidly so that any insights can be incorporated into the next IRP.	NS Power will consider timing as part of the Action Plan and agrees that this data will be valuable (note that in the Draft Report, this has been updated to item #2b).
Demand Response	SBA / Daymark	Demand Response resources can provide cost effective capacity or grid services. NSP's Action Plan calls for the creation of a Demand Response Strategy with a target capacity of 75 MW (Slide 57). We caution on the limitation placed by identifying Demand Response potential of only 75 MW. This resource needs more examination to understand its true size potential and cost for different levels of DR.	NS Power accepts this feedback and has re-worded Action Plan item #4 accordingly, adding "Available resource cost, flexibility, and reliability may inform pursuit of additional Demand Response capability."
IRP Process / Overall IRP	Town of Wolfville	[S]mall communities like Wolfville lack both the resources and expertise to meaningfully engage in a necessarily complex and lengthy process like the IRP. We've been very fortunate to receive patient and expert guidance from a number of helpful individuals and groups, but still don't feel terribly confident that we've fully understood and engaged with the process. You and your colleagues have made every effort to make the IRP process accessible to us, but we believe that our efforts, and those of communities throughout Nova Scotia endeavouring to address climate change, would be well served by an updated mandate to support climate change and environmental concerns within the IRP process in a way similar to the Consumer Advocate or the Small Business Advocate.	Interest group/community funding is a policy matter beyond the scope of NS Power's IRP exercise. NS Power thanks the Town of Wolfville for its participation in this process.
Reliability	Town of Wolfville	It was encouraging to learn that all scenarios under consideration in the IRP process satisfy NS Power's reliability target. Reliable and predictable access to electricity is vitally important to Nova Scotians and will be become increasingly so as efforts to electrify transportation and heating systems in communities proceed.	NS Power Acknowledges and agrees with this. NS Power views the addition of a Reliability Screening phase to this IRP process as positive.
Fossil Fuel Generation	Town of Wolfville	The Town of Wolfville appreciates that an accelerated coal phase out scenario was considered as part of the IRP process. We note that, in the rate impact comparison, substantially similar scenarios that included coal phase-out by 2030 and 2040 were projected to have similar rate implications by 2040. There are both short- and long-term benefits to an accelerated phase-out of coal and other fossil fuels: it has recently been confirmed that we have drastically underestimated the health impacts of air pollution on human health; the latest air quality research suggests that in the US, the health benefits alone are enough to justify an immediate transition away from fossil fuels.	The scope of the IRP does not extend to health impacts of pollution; however, NS Power has indirectly included this in its IRP metrics by providing data on emissions reductions over various portions of the IRP planning horizon.
Rate Impact Policy	Town of Wolfville	The rate impact comparison also illustrates the inequitable economic implications associated with high levels of Distributed Energy Resource (DER) adoption. By 2040, the models suggest that high DER uptake could increase electricity costs by 10%, or 2 cents/kWh. While this increase would be experienced by all rate payers, under the current regulatory regime governing Distributed Energy Resources – which limits the scope and scale of electricity-producing resources that can be connected to local distribution system –its impact would not be equitably distributed. For example, Nova Scotians with the financial capacity to both own their own homes and invest in solar PV systems would experience significantly less impact that those not in a financial position to do so. The possibility that public policy not only enables this, but is in fact subsidizing such investments, facilitating access to reduced energy costs by the wealthiest	NS Power Acknowledges these points. The Company's current rate design, with the significant recovery of fixed costs in the variable energy charges, does create a cross-subsidy of customers who self-generate by customers who do not self-generate. Though outside the scope of the IRP, it is understood that with the potential for continued growth of DER in the province, revision to the Company's rate structures will be required to address this cross-subsidization and to provide better price signals for customers considering self-generation as to the value of the generation to the system and for all customers.

		members of our society with the modelled implication of increasing the burden on the less affluent, is in urgent need of re-examination and consideration.	
Emissions Reduction	Town of Wolfville	SSG's modelling projects that, under scenario 3.2c, should the Town of Wolfville achieve the working targets in its draft climate change mitigation plan, it would achieve a 53% reduction in GHG emissions by 2030, in-line with the emissions reductions goal legislated by the Province in the Sustainable Development Goals Act (2019). It also projected that the Town's climate change mitigation efforts would realize essentially identical emissions reductions under both the NEB 2018 and Net Zero 2050 / Mid Electrification / Current Landscape scenarios – both of which would fall far short of the provincial emissions reductions goal mandated by the Sustainable Development Goals Act (2019).	NS Power notes that the Net Zero 2050 emissions trajectory is designed to achieve 1.4MT of GHG emissions in 2045, and would be on a path to continue toward 0.5MT of GHG emissions in 2050 which has been assumed to meet the criteria of net-zero, with the 0.5MT of emissions being offset by another policy or action in the province.

2020 IRP - Sustaining Capital Forecast (Nominal $) (k$) - 2040 Mandatory Retirement Profile												
	Lingan 1	Lingan 2	Lingan 3	Lingan 4	Pt Aconi	Tupper	Trenton 5	Trenton 6	TUC 1	TUC 2	TUC 3	TUC 6
2021	$ 15,521	$ -	$ 4,465	$ 4,465	$ 15,719	$ 5,386	$ 6,931	$ 5,480	$ 4,130	$ 3,875	$ 11,718	$ 7,322
2022	$ 4,642	$ -	$ 5,006	$ 5,110	$ 9,794	$ 6,532	$ 12,865	$ 5,675	$ 7,030	$ 6,614	$ 4,129	$ 3,806
2023	$ 5,228	$ -	$ 5,228	$ 5,622	$ 16,797	$ 5,721	$ 28,040	$ 6,059	$ 5,449	$ 7,837	$ 5,552	$ 2,596
2024	$ 5,780	$ -	$ 8,579	$ 8,579	$ 12,196	$ 7,091	$ 6,095	$ 5,561	$ 5,175	$ 4,905	$ 4,492	$ 2,282
2025	$ 5,626	$ -	$ 16,047	$ 7,025	$ 9,454	$ 5,859	$ 6,683	$ 6,139	$ 4,782	$ 5,266	$ 6,356	$ 5,996
2026	$ 7,784	$ -	$ 4,929	$ 14,156	$ 12,250	$ 5,215	$ 6,570	$ 7,656	$ 7,535	$ 30,180	$ 4,719	$ 2,374
2027	$ 5,383	$ -	$ 4,931	$ 4,931	$ 8,817	$ 17,632	$ 5,740	$ 5,101	$ 8,049	$ 7,762	$ 3,830	$ 2,635
2028	$ 5,772	$ -	$ 6,233	$ 5,772	$ 10,231	$ 7,307	$ 8,528	$ 16,281	$ 5,470	$ 15,406	$ 4,731	$ 3,215
2029	$ 15,217	$ -	$ 5,938	$ 6,436	$ 7,923	$ 5,332	$ 7,736	$ 6,852	$ 5,714	$ 5,415	$ 11,782	$ 2,519
2030	$ 7,835	$ -	$ 6,297	$ 6,297	$ 20,190	$ 7,412	$ 15,605	$ 6,520	$ 6,203	$ 4,975	$ 6,472	$ 5,453
2031	$ 7,544	$ -	$ 5,961	$ 5,442	$ 16,426	$ 5,758	$ 7,579	$ 5,810	$ 5,034	$ 9,292	$ 10,554	$ 9,318
2032	$ 5,658	$ -	$ 5,658	$ 6,219	$ 21,168	$ 7,962	$ 7,684	$ 7,718	$ 7,999	$ 6,160	$ 6,133	$ 2,673
2033	$ 6,944	$ -	$ 6,373	$ 6,373	$ 10,968	$ 8,036	$ 7,338	$ 6,701	$ 6,040	$ 5,716	$ 7,521	$ 3,164
2034	$ 6,556	$ -	$ 23,186	$ 10,458	$ 14,867	$ 5,887	$ 7,429	$ 6,779	$ 7,389	$ 7,062	$ 5,476	$ 3,223
2035	$ 6,858	$ -	$ 8,564	$ 21,581	$ 12,119	$ 18,383	$ 9,421	$ 8,384	$ 5,829	$ 5,492	$ 6,899	$ 6,931
2036	$ 10,132	$ -	$ 6,009	$ 6,009	$ 14,423	$ 7,551	$ 6,918	$ 8,561	$ 8,754	$ 5,215	$ 4,692	$ 2,894
2037	$ 18,622	$ -	$ 6,667	$ 6,011	$ 10,748	$ 6,188	$ 6,997	$ 6,218	$ 9,811	$ 10,678	$ 8,382	$ 2,715
2038	$ 7,036	$ -	$ 7,036	$ 7,745	$ 13,141	$ 8,907	$ 23,360	$ 8,290	$ 7,931	$ 8,882	$ 8,984	$ 5,993
2039	$ 7,962	$ -	$ 7,238	$ 7,238	$ 13,444	$ 7,843	$ 8,203	$ 22,868	$ 6,965	$ 11,502	$ 9,739	$ 3,071
2040	$ 8,827	$ -	$ 8,309	$ 7,571	$ 12,724	$ 7,885	$ 8,681	$ 7,948	$ 6,436	$ 7,434	$ 6,251	$ 4,444
2041	$ 9,196	$ -	$ 6,634	$ 8,250	$ 35,548	$ 7,018	$ 10,851	$ 8,222	$ 6,137	$ 5,758	$ 17,659	$ 10,880
2042	$ 7,711	$ -	$ 6,898	$ 6,898	$ 12,389	$ 11,217	$ 7,986	$ 8,433	$ 10,877	$ 6,788	$ 5,415	$ 3,259
2043	$ 7,768	$ -	$ 25,724	$ 7,768	$ 13,370	$ 23,779	$ 8,946	$ 8,168	$ 7,362	$ 8,509	$ 6,367	$ 4,486
2044	$ 7,992	$ -	$ 12,749	$ 31,115	$ 18,969	$ 7,176	$ 10,870	$ 9,545	$ 7,691	$ 7,288	$ 8,436	$ 3,391
2045	$ 26,414	$ -	$ 10,439	$ 10,439	$ 14,049	$ 10,406	$ 9,931	$ 9,122	$ 7,105	$ 6,695	$ 14,498	$ 8,450

2020 IRP - Sustaining Capital Forecast (Nominal $) (k$) - 2030 Mandatory Retirement Profile

	Lingan 1	Lingan 2	Lingan 3	Lingan 4	Pt Aconi	Tupper	Trenton 5	Trenton 6	TUC 1	TUC 2	TUC 3	TUC 6
2021	$ 15,521	$ -	$ 4,465	$ 4,465	$ 15,719	$ 5,386	$ 6,931	$ 5,480	$ 4,130	$ 3,875	$ 11,718	$ 7,322
2022	$ 4,642	$ -	$ 5,006	$ 5,110	$ 9,794	$ 6,532	$ 12,865	$ 5,675	$ 7,030	$ 6,614	$ 4,129	$ 3,806
2023	$ 5,228	$ -	$ 5,228	$ 5,622	$ 16,797	$ 5,721	$ 28,040	$ 6,059	$ 5,449	$ 7,837	$ 5,552	$ 2,596
2024	$ 5,780	$ -	$ 8,579	$ 8,579	$ 12,196	$ 7,091	$ 6,095	$ 5,561	$ 5,175	$ 4,905	$ 4,492	$ 2,282
2025	$ 5,626	$ -	$ 8,042	$ 7,025	$ 9,454	$ 5,859	$ 6,683	$ 6,139	$ 4,782	$ 5,266	$ 6,356	$ 5,996
2026	$ 7,784	$ -	$ 4,929	$ 5,992	$ 3,678	$ 5,215	$ 6,570	$ 7,656	$ 7,535	$ 30,180	$ 4,719	$ 2,374
2027	$ 5,383	$ -	$ 4,931	$ 4,931	$ 2,512	$ 6,547	$ 5,740	$ 5,101	$ 8,049	$ 7,762	$ 3,830	$ 2,635
2028	$ 5,772	$ -	$ 6,233	$ 5,772	$ 2,872	$ 7,307	$ 8,528	$ 6,614	$ 5,470	$ 15,406	$ 4,731	$ 3,215
2029	$ 6,595	$ -	$ 5,938	$ 6,436	$ 2,459	$ 5,332	$ 7,736	$ 6,852	$ 5,714	$ 5,415	$ 11,782	$ 2,519
2030	$ 7,835	$ -	$ 6,297	$ 6,297	$ 3,241	$ 7,412	$ 7,487	$ 6,520	$ 6,203	$ 4,975	$ 6,472	$ 5,453