# BEFORE THE

# NOVA SCOTIA UTILITY AND REVIEW BOARD

**IN THE MATTER OF:** The *Public Utilities Act*, R.S.N.S., 1989, c. 380, as amended

- and -

**IN THE MATTER OF:** An Application by Nova Scotia Power Incorporated for approval of Air Emissions Strategy capital projects.

**SUPPLEMENTAL EVIDENCE FILED BY ROBERT M. FAGAN, SYNAPSE ENERGY ECONOMICS**

**ON BEHALF OF:**

**THE NOVA SCOTIA UTILITY AND REVIEW BOARD STAFF**

# PUBLIC Version

**MAY 19, 2006**

**SUPPLEMENTAL EVIDENCE OF**
**ROBERT M. FAGAN**

**TABLE OF CONTENTS**



**EXHIBITS**

**BEFORE THE NOVA SCOTIA UTILITY AND REVIEW BOARD**

**SUPPLEMENTAL EVIDENCE OF ROBERT M. FAGAN**

**ON BEHALF OF THE NOVA SCOTIA UTILITY AND REVIEW BOARD STAFF**

## I. INTRODUCTION AND QUALIFICATIONS

**Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.**

A. My name is Robert M. Fagan. I am a Senior Associate at Synapse Energy Economics Inc. ("Synapse"), 22 Pearl Street, Cambridge, Massachusetts, 02139.

**Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.**

A. I am an energy economics analyst and mechanical engineer with 20 years of experience in the energy industry. My work has focused primarily on electric power industry issues, especially: economic and technical analysis of regulated electric utility issues and competitive electricity markets; electric industry energy, capacity and transmission pricing structures; and assessment and implementation of demand-side resource alternatives. I hold an M.A. from Boston University in Energy and Environmental Studies and a B.S. from Clarkson University in Mechanical Engineering.

**Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NOVA SCOTIA UTILITY AND REVIEW BOARD IN THE MATTER CURRENTLY BEFORE THE BOARD?**

A. Yes. I submitted direct testimony on January 30, 2006.

**Q. PLEASE SUMMARIZE YOUR INVOLVEMENT IN THE MATTER CURRENTLY BEFORE THE BOARD.**

A. Synapse was retained in November, 2005 by the UARB Staff to provide analytical support in the matter of NSPI's Application for Approval of Air Emission Strategy Capital Costs. Synapse also retained a subcontractor, Mr. Rui Afonso of Energy and Environmental Strategies, to assist in this matter. We analyzed NSPI's initial application, conducted a Lingan station site visit in December 2005, submitted a series of information requests in December, 2005, and then developed direct evidence filed in January 2006 based on the application, the site visit, and the set of responses by NSPI to the information requests.

Subsequent to January 30, the initial hearing dates were postponed and a technical conference was held on March 6-7, 2006, in Halifax. I attended that technical conference, and subsequently developed and submitted additional information requests to NSPI. On April 7, 2006 NSPI submitted supplemental evidence and responded to the information requests submitted after the technical conference. On April 21, 2006, I submitted another round of information requests. I received responses to those requests on May 5, 2006. Using NSPI's initial application, the supplemental evidence filed on April 7, and the responses to information requests, I then developed this supplemental testimony.

**Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?**

A. The purpose of my testimony is to supplement the information provided in my January 30, 2006 testimony based on a review and analysis of NSPI's supplemental testimony, technical conference information, and responses to information requests received since January.

**Q. PLEASE SUMMARIZE THE SALIENT POINT OF YOUR TESTIMONY FROM JANUARY 30, 2006.**

A. My overall conclusion based on the information available up to January 30, 2006 was that it was unreasonable to assume, based on the evidence submitted in the application and the subsequent information request responses, that the 320 MW wet scrubber option is the least cost choice for $SO_2$ emissions reduction to meet the Province's emissions regulations.

## II. SUMMARY CONCLUSION

**Q. BASED ON ALL THE EVIDENCE SUBMITTED BY NSPI, THE INFORMATION PROVIDED AT THE MARCH 6-7, 2006 TECHNICAL CONFERENCE, AND RESPONSES TO INFORMATION REQUESTS, WHAT IS YOUR OVERALL CONCLUSION CONCERNING NSPI'S AIR EMISSIONS STRATEGY APPLICATION FOR INSTALLATION OF FLUE GAS DESULPHURIZATION (FGD) EQUIPMENT AT LINGAN STATION UNITS 3 AND 4?**

A. My overall conclusion in respect of the FGD equipment remains the same as stated in my January direct testimony. Based on the updated review and findings presented in the following section it is still not reasonable to assume that the 320 MW wet scrubber option (i.e., the FGD alternative) is the least cost choice for $SO_2$ emissions reduction, especially in comparison to using lower sulphur fuels (i.e., the No FGD alternative) to meet emissions requirements.

**Q. ON WHAT BASIS DO YOU DRAW THIS CONCLUSION?**

A. I draw this conclusion based on review of the voluminous information and results provided by NSPI in response to the information requests. I rely heavily on analysis of the Strategist modeling results reported in response to Synapse IR-37.

**Q. WHAT DO NSPI'S STRATEGIST ANALYSES DEMONSTRATE?**

A. NSPI's analyses demonstrate that the difference in net present value ("NPV") costs between the FGD and the No FGD alternative are highly sensitive to input assumptions; and that the comparative net benefits of NSPI's preferred FGD option are not robust across a range of possible or even highly reasonable assumptions, contrary to NSPI's claim in its supplemental evidence that the FGD proposal is "highly robust"[1]. The results are particularly sensitive to future sulphur dioxide regulation assumptions, and the potential cost of complying with the impact of any carbon dioxide regulations.

**Q. DOES NSPI PRESENT A COMPELLING CASE FOR THE FGD OPTION?**

A. No. Even when viewing NSPI's sometimes questionable input assumptions and modeling methods in the most favorable light, at best NSPI's analytical results indicate an economic toss-up between 1) emissions control using FGD equipment, and 2) emissions control using lower-sulfur fuels. The margin of NPV Benefit is extremely thin, compared to the overall costs incurred over the 20-year time period 2010-2029. Thus, no compelling conclusion can be drawn that an FGD alternative is a more "economic" choice than a No FGD alternative. Independent of any concerns with modeling methodologies or the reasonableness of input assumptions or forecasts, a NPV Benefit of

[1] NSPI Supplementary Evidence, April 7, 2006, page 7.

$130 million with the base case FGD choice on a total PV utility cost ($2006) of approximately $[redacted] billion - i.e., about [redacted]%[2] - is too small to indicate an urgent need to put in the wet scrubber.

**Q. DO YOU HAVE ANY CONCERNS WITH THE MODELING METHODS USED?**

A. Yes, I have two major concerns. There is i) a modeling anomaly and ii) two forms of manual adjustment to the modeling results that were not present in NSPI's Application's initial Strategist modeling runs or the first round of sensitivity cases (#1 through 18), but that are present in the results reported in the response to information requests and NSPI's Supplementary Evidence of April 7, 2006. These new elements significantly impact the NPV Benefit results. They are worrisome analytical irregularities; and their presence causes me to question the validity of some of the "NPV Benefit" results presented in summary form in response to Synapse IR-37, Attachment 3.

**Q. PLEASE DESCRIBE THE MODELING ANOMALY.**

A. The modeling anomaly consists of the existence of a large capital cost for new generation in sensitivity cases #19 through #49 for the No FGD alternative, with no parallel assumption for the FGD alternative in each of those cases. The new generation is claimed necessary to meet SO2 restrictions, yet the claim is not adequately supported given the significance of its impact on the modeling results and given the presence of existing (modeled) generation whose operation would appear to be sufficient in meeting the $SO_2$ constraints. If such generation is indeed not needed to meet $SO_2$ restrictions, then its inclusion in the modeling framework leads to an overstatement of NPV Benefit

[2] Based on NSPI's response to Synapse IR-37, Attachment 2, worksheet "Base 2.5%S FGD vs None to 2029", [redacted] PV utility cost for FGD alternative over 2010-2029, in $2010, discounted back to $2006 at 6.85%.

for the FGD alternative in the noted sensitivity cases. If the generation is not needed, then corrected Strategist results and associated manual adjustments may likely result in a negative NPV Benefit for the FGD alternative in many of the more recently requested sensitivity runs asked for by Synapse (i.e., #19 through #49).

**Q. PLEASE DESCRIBE THE TWO FORMS OF MANUAL ADJUSTMENT MADE BY NSPI OUTSIDE THE STRATEGIST MODELING CONSTRUCT.**

A. The two forms of manual adjustment include 1) an extension of the time period of analysis from a terminal point of 2025 to a terminal point of 2029; and 2) addition of flue gas conditioning (FGC) costs for the No FGD alternative.

Much of the NPV Benefit associated with the FGD alternative occurs within the time period extension (i.e., between 2026 and 2029); given the importance of this incremental period to the modeling results, it is unfortunate that the more rigorous and consistent Strategist framework was not employed for the analysis of these periods. I note that it does not appear that Strategist was used to model the full 2010-2029 period for any of the cases. The only evidence provided by NSPI was a summary of the year-by-year capital and operating costs and the discounting process for case #1[3], which appears to use Strategist outputs for the first 16 years of the period (2010-2025) but which does not document exactly how the remaining cost streams were generated.

The need for FGC for the No FGD alternative does not appear to be adequately supported, and even if the FGC is necessary, the costs included are not well-supported; a more prudent approach would consider a need for FGC as a sensitivity case, yet NSPI has included these costs in all of the cases.

[3] NSPI response to Synapse IR-37, Attachment 2.

**Q. IS NSPI'S CHOICE OF A "BASE" CASE REASONABLE?**

A. Not necessarily. NSPI's base case includes 1) an assumption of significantly stricter sulphur dioxide emission regulations than currently exist, and 2) an assumption that greenhouse gas impacts (e.g., carbon dioxide emission credit costs) will be zero in all years of the analysis. These assumptions create an unsupported bias in favor of the FGD equipment option. Since these factors have such a large impact on the economic analysis, a more reasonable base case might instead use 1) the existing Provincial sulphur dioxide regulations, which call for a reduction in $SO_2$ emissions from the current 108.75 kilotonnes per year to 76.2 kilotonnes per year beginning in 2010, but at this point do not call for further reductions commencing in 2020[4]; and 2) NSPI's own "Basic Modeling Assumptions for Long Term Energy Plans", which contain a mid-range price for carbon dioxide credit costs equal to $**/tonne of $CO_2$ for the years 2008-2012, $**/tonne in 2013-2017, and $**/tonne in 2018-2022[5]. NSPI states in this document that

"[redacted]."

Thus NSPI's own planning document indicates that a [redacted]. Zero-cost $CO_2$ emissions and stricter sulphur regulations might best be treated as "sensitivity" cases, not as a "base" case as NSPI has done.

[4] Nova Scotia Air Quality Regulations, made under Section 112 of the Environment Act, S.N.S. 1994-95, c. 1, O.I.C. 2005-87 (February 25, 2005, effective March 1, 2005), N.S. REg. 28/2005, Schedule C, Annual Sulphur Dioxide, Nitrogen Oxidde and Mercury, Emission Allocations for Nova Scotia Power Incorporated. Included as Appendix I to NSPI's original Air Emissions Strategy Capital Application, November 2005.
[5] NSPI response to Synapse IR-9, Confidential Attachment 1, page 20.

## III. REVIEW AND FINDINGS

1. NSPI Strategist Modeling Results

**Q. PLEASE SUMMARIZE THE NEW MODELING WORK UNDERTAKEN BY NSPI ON WHICH MUCH OF THIS SUPPLEMENTAL EVIDENCE IS BASED.**

A. NSPI updated its original set of deterministic analyses using the Strategist modeling tool, and performed additional manual adjustments. In the original runs (cases 1 through 18) I understand that NSPI used a 4% sulphur fuel blend for the Lingan 3 and 4 units for the FGD alternative. However, the proposed FGD equipment is designed for a target fuel blend of 2.5% sulphur. Thus NSPI's original analysis of 18 cases had used fuel inputs that were not consistent with the equipment design. The new base case (run #1) and all of the other cases use a 2.5% sulfur fuel blend, instead of a 4% sulfur blend for the FGD alternative in all cases. This change increases the costs of the FGD option because a fuel blend with average lower sulfur content (2.5% vs. 4%) is more expensive than one with higher sulfur content. In NSPI's base case #1, this increase was reported by NSPI to be equal to $[redacted] million on a "NPV Benefit" basis[6].

NSPI also ran sensitivity cases (19 through 59) based on post-technical conference requests by Synapse and a number of the other intervenors.

In addition to these new runs and the fuel blend changes, NSPI added two NPV Benefit equation components to the alternatives, outside of the Strategist modeling construct, based on 1) increasing the time period of analysis to 2029 instead of ending it at 2025, and 2) adding "flue gas conditioning" (FGC) costs for the No FGD alternative in all of the cases.

[6] NSPI response to Synapse IR-37, Attachment 3, "hidden" column m, which is titled "Increase in FGD Plan Cost versus original 18 runs on 4+%S WLSFO FGD".

**Q. WHAT ARE THE RESULTS OF THE UPDATED NSPI MODELING?**

A. Exhibit RMF-1 contains the summary information provided by NSPI as Attachment 3 to their response to Synapse IR-37. The source of the data is the excel file "summary" worksheet. It contains a listing of the 61 cases modeled by NSPI in the Strategist environment. The Exhibit also contains additional manual adjustment data used by NSPI to compute the NPV Benefit column in the table. In the original file, these adjustments were entered manually into an excel cell and were not readily transparent to someone viewing the table. I have included a column explicitly showing these adjustments, one to account for the "NVP Benefit" associated with the years 2026-2029, which were not modeled in Strategist; and one to account for NSPI's computation of the NPV of the use of flue gas conditioning, which NSPI claims is needed for the No FGD alternative.

I have also included a computation illustrating the relative magnitude of the NPV Benefit, based on modeled total utility NPV costs over the 20-yr. period 2010-2029.

I have also added a comment column to note two particular attributes of certain scenarios: i.e., pointing out that the first set of scenarios (1 through 18) generally exclude the potential costs of carbon dioxide credits (except for 6, 7 and 8); and that most of the second set of scenarios (19 through 59) include large (on the order of $[redacted] million) incremental capital costs in years 2020 through 2025 for the No FGD alternative. I address each of these circumstances in the sections that follow, but I note here that each of these attributes of NSPI's presentation and modeling choices bias the results in favor of the FGD alternative.

**Q. DO THE ANALYSES PROVIDE ANY INSIGHT INTO GENERIC RESOURCE PLANNING ISSUES FOR NSPI?**

A. Yes. The analyses demonstrate the sensitivity of overall 20-year NPV utility costs to core assumptions such as load level, the extent of use of renewable generation, and the timing of new resource acquisition, independent of the choice among $SO_2$ emissions reduction options. NPV utility costs vary by more than $[redacted] depending on input assumptions.[7] This sensitivity thus provides some insight into interrelated resource planning issues that are not an explicit part of this proceeding, but as noted by Dr. Stutz in his May 19, 2006 Additional Evidence, ought to be evaluated prior to committing to such a significant capital expenditure as that requested by NSPI for the FGD alternative.

2. Treatment of Provincial Sulphur Dioxide Regulation

**Q. PLEASE EXPLAIN NSPI'S TREATMENT OF SULPHUR DIOXIDE REGULATIONS IN THE MODELING INPUTS.**

A. NSPI used the Province's existing regulation structure for the $SO_2$ emissions cap between 2010 and 2019, at a level of 72.5 kilotonnes. Commencing in 2020, NSPI assumed that the regulations would be changed to constrain sulphur emissions even further, from the 2010 level of 72.2 kilotonnes to approximately one-half of that, or 36.2 kilotonnes.

**Q. IS THIS A CRITICAL ASSUMPTION?**

A. Yes. Assuming that the regulations do not change and the $SO_2$ emissions cap in 2020 remains the same as in 2010, at 76.5 kilotonnes/year, the results of the modeling are quite different, understandably. Without such an increased constraint, the total cost of low-sulfur fuels for the No FGD alternative is considerably less, and the scrubbing benefit accruing to the FGD alternative is less. Thus, as shown on Exhibit RMF-1, the NPV

[7] See Exhibit RMF-1.

Benefit swings from positive $130 million for the FGD alternative (as shown in case #1) to negative $48 million for the FGD alternative (as shown in case #13), due solely to this $SO_2$ regulation assumption. These values (reproduced in Exhibit RMF-1) of positive $130 million (case #1) and negative $48 million (case #13) are based directly on NSPI's analyses and can be found in the response to Synapse IR-37, at Attachment 3, the "summary" worksheet, and also in Attachment 4 which contains year-by-year breakdowns of the Strategist results.

**Q. WHAT IF THE REGULATION WAS TIGHTENED, BUT BY A LESSER AMOUNT THAN NSPI'S ASSUMPTION?**

A. In response to a query by Dr. Stutz[8], NSPI indicated that at a $SO_2$ emission cap approximately midway between the existing regulations (i.e., 72.5 kilotonnes of $SO_2$ emitted/year from 2010 forward) and NSPI's presumed 36.2 kilotonnes of $SO_2$/year constraint, the NPV Benefit would remain at approximately negative $48 million, indicating an apparent non-linearity in the relationship between NPV Benefit and the extent of the $SO_2$ constraint in 2020. The letter states in part:

> "Based on additional modeling with an assumed $SO_2$ reduction in 2020 to 50 ktonne, NSPI has determined the present value would be the same as the result for sensitivity 13.
>
> The partial further reduction in 2020 does not change the present value result because of the volume of petroleum coke purchased and burned fleet-wide. Under either scenario (no further change in 2020 or a reduction to 50 ktonne) the same amount of petroleum coke will be burned in the NSPI fleet. The petroleum coke will be added to non-scrubbed units so a maximum use is reached under either scenario.
>
> This result suggests to NSPI that the $SO_2$ cap will have to be reduced to lower than 50 ktonne in 2020 before a positive present value is demonstrated, although

[8]See letter dated May 5, 2006 from Rene Gallant to Dr. John Stutz.

the break-even point is not as low as the base case assumption of 36.2 ktonne. As we discussed when you raised the question, there does not appear to be a straight line relationship in present value benefits between the base case assumption and the sensitivity 13 assumption."

**Q. WHAT DO YOU CONCLUDE FROM THIS?**

A. The economics of the choice between FGD or No FGD as modeled by NSPI is highly sensitive to future Provincial emission regulations using NSPI's modeled results. The relative economic benefit of the choice of a FGD alternative is not at all robust to a consideration that $SO_2$ emission regulations could remain as is, or could tighten by another 25%. Only if the regulations tighten (in 2020) by something closer to a 50% reduction from the 2010 levels does the FGD alternative accrue additional benefit such that the NPV Benefit computation swings positive, based on NSPI's modeling.

Only if the NPV Benefit for the FGD alternative was relatively significant, and remained positive under various input assumptions could this alternative pass muster as a robust response to the emissions regulations. As noted above, the NPV Benefit level is not significant, it is relatively thin in comparison to total costs; and it doesn't remain positive under this fundamental $SO_2$ assumption. This lack of robustness is a fundamental finding that in my opinion should be given significant weight by the Board.

3. Representation of Carbon Dioxide Regulations

**Q. PLEASE EXPLAIN NSPI'S TREATMENT OF POTENTIAL CARBON DIOXIDE REGULATIONS.**

A. NSPI has incorporated the impact of potential $CO_2$ regulations within the Strategist environment for some cases, and has assumed no impact from $CO_2$ regulations for other cases, including its base case. For those cases where NSPI included carbon dioxide

regulation impacts, they assumed that all $CO_2$ constraints would be handled financially, i.e, $CO_2$ credits would be purchased to cover $CO_2$ emissions costs beyond the level of $CO_2$ emissions that would be "allowed". As noted, the mid-range value (i.e., the "p50" value) for $CO_2$ emission credit cost is $[redacted]/tonne of $CO_2$ in the 2008-2012 timeframe, $[redacted]/tonne in 2013-2017, and $[redacted]/tonne in 2018-2022[9] (and all years beyond 2022). NSPI's total $CO_2$ emissions in its base case, FGD alternative range from [redacted] kilotonnes in 2010 to [redacted] in 2025[10]. The allowed emissions under the p50 case are [redacted] kilotonnes in 2010 and [redacted] kilotonnes in 2020[11]. $CO_2$ emissions credits are required for the difference between $CO_2$ emitted and the $CO_2$ emission allowance.

**Q. IF CARBON DIOXIDE REGULATIONS ARE IMPOSED, IS THE EFFECT LIKELY TO BE SIGNIFICANT ON NSPI'S CHOICE OF EMISSION CONTROL ALTERNATIVE?**

A. Yes. NSPI computed a differential NPV Benefit impact of $114 million, based on comparing NSPI's base case (case # 1, $130 million NPV Benefit) with its medium-range $CO_2$ price case (sensitivity # 6), as shown on Exhibit RMF-1. Sensitivity case #6 shows a NPV Benefit of $16 million, or only two-tenths of one percent of the baseline utility costs over the 2010-2029 timeframe, for the FGD alternative.

Thus, the magnitude of $CO_2$ credit price impact is nearly as large as NSPI's base case NPV Benefit for the FGD alternative. This is a striking example of the sensitivity of these types of calculations to changes in critical input assumptions.

[9] NSPI response to Synapse IR-9, Attachment 1, page 20.
[10] NSPI Strategist run, in response to Synapse IR-37, Confidential Attachment 1, pages 83-84 of 180.
[11] NSPI response to Synapse IR-9, Attachment 1, Table 5.1, page 17.

**Q. WHAT IF CARBON DIOXIDE REGULATIONS RESULT IN HIGHER CO2 CREDIT PRICES, SUCH AS THOSE PRICES ASSOCIATED WITH THE "P90" CARBON CREDIT PRICE SCENARIO AS DESCRIBED BY NSPI[12]?**

A. The NPV Benefit results modeled by NSPI will swing from positive $16 million to negative $6 million in the P90 case (case #7), and negative $23 million in a higher-price $CO_2$ case (case #8) reflecting a credit price increase ranging from 17-32% higher than the P90 case.

4. Capital Cost Streams for Certain Sensitivity Analyses

**Q. PLEASE EXPLAIN THE MODELING ANOMALY YOU MENTIONED IN YOUR SUMMARY CONCLUSION CONCERNING THE CAPITAL COSTS FOR THE NO FGD ALTERNATIVE IN MANY OF THE SENSITIVITY CASES.**

A. The anomaly consists of highly significant additional costs for new generation present in the capital cost streams for the No FGD alternative, but not present in the capital cost streams for the FGD alternative, for all sensitivity cases #19 through #49[13].

Generally NSPI used the same input assumptions for the FGD and No FGD alternatives except for the way in which the presence (or absence) of FGD equipment has an impact on the choice of fuels used when meeting the emissions regulation.[14] Essentially, the presence of the FGD equipment allows for the purchase of less

[12] NSPI described mid-range (P50), low (p10) and high (p90) $CO_2$ price scenarios in its "Basic Modeling Assumptions for Long-Term Energy Plans", dated November 2005 and included as Attachment 1 to Synapse IR-9.
[13] The capital cost streams were available in Attachment 4 in response to Synapse IR-37, and in the accompanying Strategist runs, for many but not all of the sensitivity cases 19 through 49. Based on NSPI's rationale stated in response to Synapse IR-50, and the fact that all of the other sensitivity cases in which capital costs were not directly provided use the same 0.5% load growth, I surmised that all of those cases also included incremental capital costs for the new generation in the No FGD alternative of each case.
[14] See for example NSPI's response to UARB IR-22 a) & b), which states in part "The annual capital charges for each plan in any year are the sum of the annual capital charges for new projects that have come into service up to that point in time. Therefore since the only difference in the two plans is the addition of the FGD, the capital cost difference between the two plans in 2010 and 2020 is the capital charge related to the FGD in those years."

expensive, higher sulphur fuels. Thus, the modeling exercise allows one to examine the economic tradeoffs between removing the sulphur after the fuel (i.e., coal and petcoke) has been burned, or purchasing lower-sulphur fuels in the first place and not having to remove the sulphur at the back end of the process.

The anomaly is the fact that the capital cost streams for the No FGD alternative in sensitivity cases 19 through 49 all appear to contain an incremental capital cost for new generation equipment that is not contained in the FGD alternative for the same cases. This incremental cost appears to range between [redacted] million in years 2021-2025, and is approximately $[redacted] million in 2020, based on an inspection of the trends in NSPI's capital cost streams for sensitivity cases #19 and #1, provided here as Exhibit RMF-2. This capital cost increment is due to the presence of capital costs for a new 270 MW CC unit, modeled as being installed in 2020, as noted in the table in NSPI's response to Synapse IR-50 which is included here as Exhibit RMF-3. NSPI's year-by-year results summarizing capital and operating costs for sensitivity #19 are provided in Exhibit RMF-4.

In NSPI's response to IR-50, NSPI mistakenly stated that the $SO_2$ constraint is stricter in 2020 than in 2019 (it is not stricter for sensitivity case #19, the subject of the IR) and also stated that *new generation* is required to meet the SO2 constraint:

> "In the Base Plans, with load growth at 1% the generation/dispatch plans are the same except for the FGD itself. In the 0.5% load growth case (Sensitivity 19) this changes in 2020 when a new generation unit (best available technology economically available) is required in the No FGD case to economically meet the $SO_2$ constraint. In the FGD case the 270 MW of new generation is not required in order to meet the $SO_2$ constraint. In Sensitivity 19 both cases have a demand growth rate of 0.5% per year."[15]

[15] NSPI, response to Synapse IR-50 (a).

NSPI includes a table showing the introduction of a 270 MW combined cycle unit in 2020 in the No FGD case, yet there is no equivalent generation capacity need in the same year in the FGD case. If one presumes that the emission regulation can be met using lower sulphur fuels in the coal units, or using greater output from the zero-sulphur-emitting gas-fired units – which upon initial inspection of the Strategist unit report appears to be the case - it is unclear why NSPI has included this additional capital cost in the modeling exercise.

For example, attached as Exhibit RMF-5 are pages from the Strategist unit report for sensitivity 19, the No FGD alternative, showing the results for the Province's [redacted] units for the years 2017-2023. While inspection of these reports is not sufficient to state absolutely that the new 270 MW CC unit is not necessary to meet $SO_2$ constraints, an initial examination reveals that there is unused capacity at [redacted] unit modeled as being installed in 2018. On an average annual basis, the unused capacity at these [redacted] units exceeds that of the new 2020 unit, thus calling into question a need for a new unit solely for the purpose of meeting the emissions constraints. I note that this exhibit excludes any additional unit report information for the coal units, which also may have the ability to utilize a greater percentage of lower sulphur fuel.

**Q. WHAT IS THE EFFECT OF INCLUDING THE ADDITIONAL GENERATION COSTS IN THE "NO FGD" CASE AND NOT IN THE "FGD" CASE?**

A. If the generation is not needed to meet the emission constraint, then the effect of including it in the No FGD model run is to incorrectly increase the costs associated with the No FGD alternative relative to the FGD alternative. The amount of that increase

depends on a comparison of the capital cost streams beyond 2025, for example to determine if the unit is ever installed for the FGD alternative. Without a more careful consideration of the generation supply planning assumptions, it is hard to put a number on the value of the increase. However, if one simply looked at the differential capital costs associated with the No FGD stream of capital costs in sensitivity case #19, the stream of $[redacted] million in 2020 and $[redacted] million in 2021-2025 equates to a net present value ($2006) of approximately $[redacted] million, as shown in Exhibit RMF-2. Even an impact that is one-quarter of that amount would lead to negative NPV Benefit for the FGD alternative in many of the sensitivity cases, as seen by inspection of the results of cases 19 through 49 on Exhibit RMF-1.

5. Extension of Time Period of Analysis from 2010-2025 to 2010-2029

**Q. PLEASE EXPLAIN NSPI'S USE OF AN INCREASED TIME PERIOD OF ANALYSIS.**

A. NSPI has recognized that using a 16-year period (2010-2025) was inconsistent with the 20-year life of the FGD equipment and the planned retirement dates for Lingan 3 and 4. They have thus added four more years to the analysis (2026 through 2029), and accounted for additional net benefit associated with the FGD option in those years. However, the adjustment to address the additional four years has been done outside of the Strategist environment and is a somewhat involved computation. A preferred method would have utilized Strategist to maintain consistency with the general analytical approach used. In particular, much of the benefit associated with the FGD alternative occurs in the last four years (2026-2026), and a more transparent methodology for computing the benefit would have been prudent.

**Q. DO YOU HAVE OTHER CONCERNS WITH NSPI'S METHOD FOR DEALING WITH THE "OUT YEARS"?**

A. Yes. The costs for carbon dioxide regulations are listed in NSPI's modeling assumptions up to year 2022. In the sensitivity cases where $CO_2$ credit costs are explicitly accounted for, the 2018-2022 $CO_2$ credit cost value is used for 2023-2025, and implicitly for 2026-2029. It is not clear that the same value should continue be used for those later years, as increased CO2 credit costs in those years could significantly reduce the associated NPV Benefit.

6. Flue Gas Conditioning Requirements and Impact on No FGD Alternative

**Q. WHAT IS NSPI'S PROPOSED FLUE GAS CONDITIONING (FGC)?**

A. Flue Gas Conditioning is proposed by NSPI for Lingan units 3 and 4 for the No FGD alternative. It involves retrofit to allow for "the addition of sulphur tri-oxide ($SO_3$) to enhance particulate collection performance"[16]. When lower sulphur fuel is used, there is a chance of reduced performance of the electrostatic precipitators, and thus increased opacity of the flue gas. NSPI states:

> "Based on test results provided in SEB IR-61 and the associated increase in opacity, NSPI is confident flue gas conditioning is required at Lingan for all fuels with less than 0.5% sulphur. In the case of fuels between 0.5% and 1% sulphur, as demonstrated by the Columbian burn, NSPI has been able to control opacity under test conditions. It is NSPI's assumption that under upset conditions or wet fuel conditions flue gas conditioning will be required[17]".

In the response to Synapse IR-16, NSPI states that low sulfur coal used at Lingan has a sulfur content of 0.7%.

[16] NSPI response to Synapse IR-57.
[17] NSPI response to Synapse IR-58.

**Q. HAS NSPI ADEQUATELY DOCUMENTED A NEED FOR FLUE GAS CONDITIONING?**

A. No. NSPI has asserted a need for FGC, as noted above, but has not adequately documented the need, or the approximately $7 million NPV cost[18]. In the response to IR-58, NSPI indicates that FGC is needed under certain conditions, even though the "test burn" did indicate acceptable precipitator performance. More comprehensive documentation is required.

**Q. HAS NSPI DOCUMENTED THE PROJECTED COSTS FOR THE FLUE GAS CONDITIONING?**

A. No. NSPI bases its FGC costs on indicative costs based on a deferred trial installation at Point Tupper station[19]. However, the costs reported in response to IR-56 are not reconciled with the values provided for FGC costs at Lingan for the No FGD alternative. It is not clear exactly how the cost stream presented in Attachment 2 of the response to Synapse IR-37 was computed; in particular, there were no explicit assumptions about the amount of time conditioning would be required, e.g., there was no documentation on how often the "upset or wet fuel conditions" noted above would arise and thus require FGC.

**Q. WHAT DO YOU CONCLUDE IN REGARDS TO THE COSTS INCORPORATED INTO THE MODEL FOR FGC FOR THE NO FGD ALTERNATIVE?**

A. It appears that FGC might be required, but it has not been definitively established. Also, the costs required if FGC is needed have not been adequately supported in this application.

[18] NSPI response to Synapse IR-37, Attachment 2, "FGC" worksheet.
[19] NSPI response to Synapse IR-56.

7. Fuel Flexibility

**Q. HAS NSPI QUANTITATIVELY DOCUMENTED THE EFFECT OF INCREASED "FUEL FLEXIBILITY" OBTAINED THROUGH INSTALLATION OF THE FGD EQUIPMENT?**

A. No. NSPI claims "fuel flexibility" as their primary reason for installing the wet scrubber.[20] However, NSPI has not quantified the value of such flexibility and therefore it is difficult to assign any particular weight to this benefit. The increased fuel flexibility logically translates to lower fuel prices, but the impacts are not directly examined other than through the broad NPV Benefit modeling, which as noted above fails to conclusively make the case for the FGD alternative. A proponent of the No FGD alternative could claim increased "capital investment spending flexibility" and be equally correct.

For example, NSPI projects close to $[redacted] million in total fuel costs in 2015[21], yet provides no direct information on the range of fuel costs for that year, or how that range differs between the FGD and the No FGD case. Thus, they have not quantified the parameters that might be used to help determine the "option value" that exists with increased fuel flexibility. Notably, NSPI also has not quantified the value associated with any lost opportunities that may arise if they become capital constrained because of installation of the FGD[22].

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

[20] NSPI Supplementary Evidence, April 7, 2006, page 8.
[21] NSPI response to Synapse IR-37, Attachment 1, pages 1 and 61.
[22] NSPI response to Dr. Stutz IR-3(b).