La Capra Associates

# NEEDS FOR AND ALTERNATIVES TO (NFAT) REVIEW OF MANITOBA HYDRO'S PROPOSAL FOR THE KEEYASK AND CONAWAPA GENERATING STATIONS

*PUBLIC VERSION*

Technical Appendix 10B

Financial Analysis Part II

*PREPARED FOR*

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# Technical Appendix 10B: Financial Analysis Part II

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# Acronyms

## Technical Appendix 10B

| | |
|---|---|
| CCGT | Combined Cycle Gas Turbines |
| D/E | Debt-equity |
| DSM | Demand Side Management |
| ESOW | Expanded Scope of Work |
| IEC | Independent Expert Consultant |
| LCA | La Capra Associates |
| LCOE | Levelized Cost of Energy |
| MH | Manitoba Hydro |
| MW | Megawatt |
| MWh | Megawatt hour |
| NFAT | Needs For and Alternatives To |
| NPV | Net Present Value |
| SOW | Scope of Work |
| TA | Technical Appendix |

# I. Introduction

## A. Scope of Report

La Capra Associates (LCA) has prepared this Technical Appendix (TA) to address elements of our Needs For and Alternatives To (NFAT) Scope of Work (LCA SOW) that pertain to the financial analysis issues and support other elements of the LCA SOW that rely on the materials in this report. The specific focus of this Technical Appendix is to assess the reasonableness of Manitoba Hydro's (MH) financial modeling related to that analysis included in the LCA SOW. This document includes supplemental analysis and review to Technical Appendix 10A that was previously filed in January, 2014.

The specific LCA SOW elements addressed by the material presented in this document include:

> *13. Test each scenario look for potential risks, including:*
>
> *a) Lower export market prices;*
>
> *b) Higher interest rates;*
>
> *c) Lower or higher domestic load growth;*
>
> *d) Droughts;*
>
> *e) Competing technologies;*
>
> *f) Fuel price changes;*
>
> *g) Carbon pricing;*
>
> *h) Government and regulatory policy change;*
>
> *i) Construction cost escalator;*
>
> *j) Economic conditions;*
>
> *k) Infrastructure failure; and*
>
> *l) Any other major risks identified.*

Some of the above risks were discussed in prior or other Technical Appendices (including 10A). This Technical Appendix relies on some of the information and methodology discussed in LCA Technical Appendix 9B: Economic Analysis and the drought discussion found in LCA Technical Appendix 5.

### B. Structure of the Report

LCA's review of MH's financial analysis as presented in this Technical Appendix is organized into eight parts.

First, in Section II, we provide a brief discussion and comparison of this document to the prior Technical Appendix.

In Section III, we analyze the impacts of drought conditions through analysis of financial metrics that were either provided by MH or discussed in Technical Appendix 10A. These drought conditions were discussed in Technical Appendix 5.

In Section IV, we examine the financial impacts of the alternative cases that were filed following the publication of the first section of this technical appendix.

# II. Summary of Financial Analysis Review (TA 10A & 10B)

MH undertook a "financial evaluation" of a subset of the development plans that were discussed above and were examined as part of their "economic evaluation." Their evaluation is contained in Chapter 11 of the August 2013 filing (along with accompanying appendices) and supplemented by various responses to discovery. The focus of their financial evaluation was to compare the impacts of different development plans on rates paid by its (domestic) customers and on the financial condition of MH, specifically in terms of the ability of the plans to absorb reductions to revenue streams (notably in the presence of drought conditions); by contrast, their economic evaluation considered the economic cost and benefit flows associated with different development plans without consideration to the potential rates to be paid by Manitoba ratepayers and the requisite financial flows that would be required to enable the net cost (and benefit) flows underlying each plan.

The first volume of this appendix contained our review of MH's filing. In particular, we analyzed the cost and rate impacts to domestic customers of the development plans that were examined by MH. We reviewed a number of key variables underlying MH's analysis including time frames and discount rates and examined the impact of alternative financial targets. Finally, we discussed the potential impacts of different risks, such as load growth changes, fuel price changes, and lower export market revenues to the rate impacts and financial risks of the various development plans.

This report supplements the first volume by examining analysis of drought as a risk factor. As such, this report is supported by work discussed in Technical Appendix (TA) 3, which discusses hydrological conditions. We also include a brief review of the financial impacts of additional development plans that were prepared by MH in response to Information Requests in this proceeding and have only recently been made available and were included as part of the expanded scope of work (ESOW).

# III. Drought Analysis

Analysis of drought is an important risk factor in the examination of hydro facilities. By directly impacting the supply of water, drought conditions reduce the potential revenue streams that can be utilized to pay for the various operating and, more importantly, finance costs that underlie the hydro facilities. Indeed, MH includes a number of sensitivity analyses around drought conditions in their filing. For purposes of this document, we concentrate on MH's discussion of the impacts of drought on the financial analysis, but the impacts of drought conditions on the economic analysis of the Preferred and other development plans can be found in TA 3.

## A. Manitoba Hydro's Drought Analysis

For their financial analysis, MH utilized the same drought characteristics that were used for the economic analysis. They examined 5-year drought periods that occurred during or slightly after the construction and in-service dates of Keeyask and Conawapa for three development plans: the All Gas plan, the K19/Gas/250 MW plan, and the K25/C31/750 MW or "Preferred" plan. The dates for the start of the 5-year periods that were analyzed are as follows:

- 2014/15 — During construction of Keeyask
- 2021/22 — Affecting early revenues from Keeyask and during construction of Conawapa
- 2027/28 — Affecting early revenues from Conawapa
- 2032/33 — Beyond early revenues from Conawapa.

This analysis was performed for all 27 scenarios (around reference, high, and low values for three variables) that were discussed in prior technical appendices.

MH's drought analysis and discussion found in the filing concentrated solely on the impact on retained earnings. MH examined the impact of additional drought cases by examining the impact on retained earnings assuming that customers' rates were held constant (under base conditions). As such, MH is assuming that retained earnings would absorb the lost revenues (rather than passing the rate increases on to customers) in order to test the impact of revenue decreases on the financial condition of the utility.

Figure 10-38, which is replicated from the filing, summarizes the results of Manitoba's analysis.

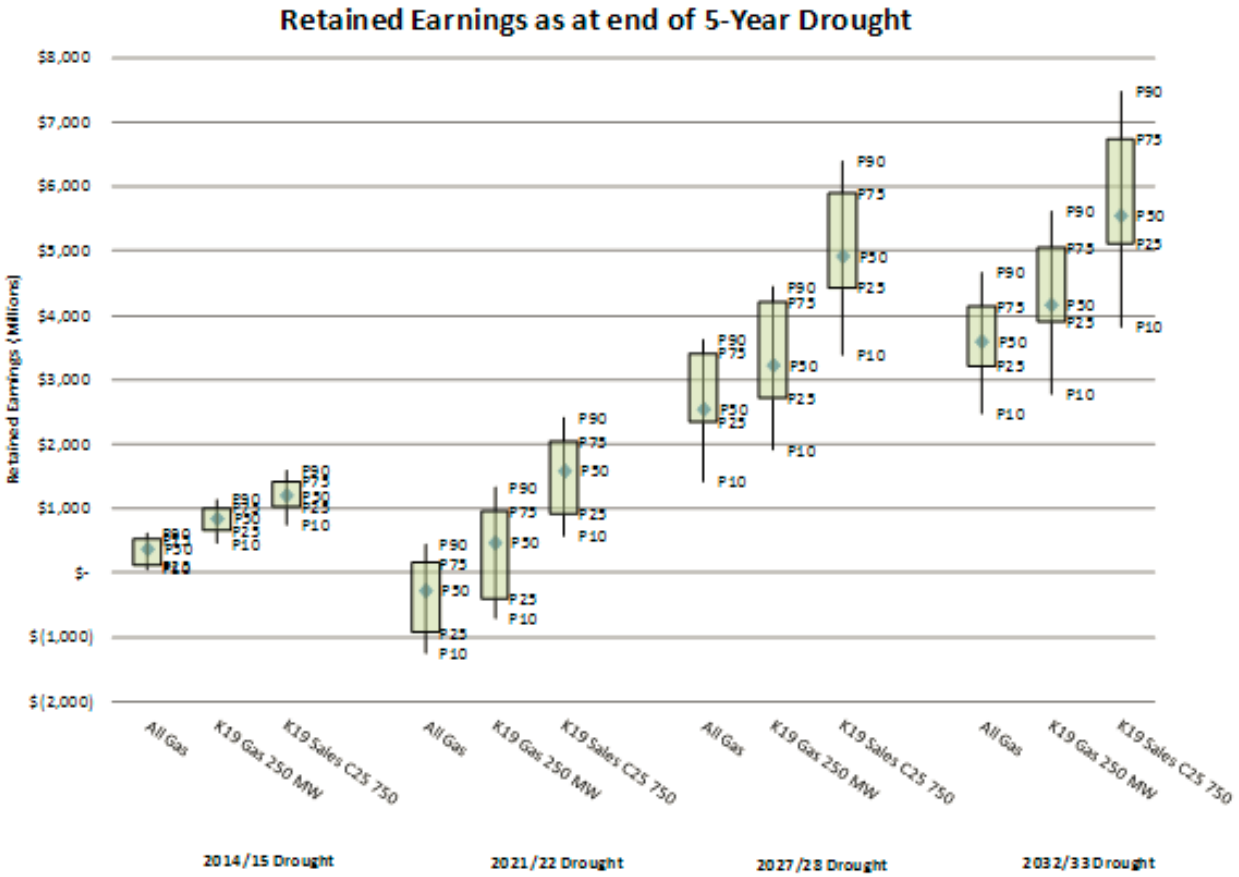


**Figure 10-38: Figure 11.9 of Manitoba Hydro's Filing**

The figure shows the range of values of the retained earnings across the various sensitivities for the three development plans with the dots within the boxes representing the P50 values. These are estimates for retained earnings following the drought, and the Preferred development plan shows the highest values for retained earnings at the end of the drought period compared to the other development plans. This is the case despite the Preferred plan having the most negative impact in terms of the size of retained earnings reductions, because the Preferred plan also has the highest retained earnings levels prior to the start of the drought periods. The All Gas plan, despite not containing any additional buildout of hydro facilities, is negatively

impacted by drought due to impacts on existing hydro facilities that are common to all development plans.

MH did not provide or discuss the debt/equity ratios implied by the retained earnings level shown in the figure, but these retained earnings may cause MH to not meet its financial target of 75% for the debt-equity ("D/E") ratio. For example, applying the approximate $1.2 billion P50 value for the 2014/15 drought period in 2019/20 yields a D/E ratio of 93% versus 88% for the preferred plan under base conditions; applying the approximate $4.9 billion P50 value for the 2027/28 drought in 2031/32 yields a D/E ratio of 83% versus the 75% target for that year.

Given that MH has set 2032 as a target year for the debt-equity ratio, additional rate increases would be required to account for the drought impacts during the 2013-2032 time period if this target is to be honored; these rate increases would be required for all development plans. Rate increases would may also be required after this period to bring the D/E ratio to target levels. For example, application of the approximate $5.5 billion P50 value for the 2032/33 drought in 2037/38 yields a D/E ratio of 79%, which is above target levels.

### B. Rate Impacts of Additional Drought Analysis

In order to examine the issue of rate impacts in more detail, we modeled an additional drought case using our spreadsheet model. We only examine the impacts of drought on the Preferred case, since other cases feature relatively larger (in percentage terms) drought impacts on retained earnings. The figure below shows the results from applying the drought conditions that represented by the 1918 water year in 2014, which would place the 1928-1942 drought in 2025 (see discussion in TA 3). Rate increases were calculated assuming that net revenues would be negatively impacted, as shown in the economic analysis discussed in TA3 and TA 9B, and required to meet the 75/25 D/E target by 2032. Figure 10-39 compares these rate increases that would be required under drought conditions to the even-annual rate increases calculated by MH for the preferred plan under reference conditions and discussed in TA 10.

| Plan # | Development Plan Short Name | Even-Annual Rate Increases (2012/13 to 2032) | Cumulative Nominal Rate Increases at 2031/32 | Cumulative Nominal Rate Increases at 2061/62 |
|---|---|---|---|---|
| 14 | K19/C25/750 (Preferred Plan) | 3.95% | 108% | 106% |
| 14 | 1918 Drought | 4.07% | 112% | 106% |

**Figure 10-39: Rate Increases for the Preferred Plan Under Reference and Drought Conditions**

Drought conditions require a higher rate increase to ratepayers during the early years of the study period to make up for the lost revenues and still meet the required retained earnings targets that underlie the 75/25 debt-equity target ratio. For the calculations above, we made no changes to the level of debt found in the Preferred plan. Though the table shows that cumulative rate increases at 2061/62 are identical for both water supply conditions, this outcome is a result of the financial model solving for rate increases necessary to achieve the 1.2 interest coverage ratio.

Rate increases (relative to the Preferred plan) would be different under various drought conditions and would still be required for certain years during the period following attainment of the D/E target ratio in the absence of drawing down of retained earnings.

These different rate increases can be seen by examining utilizing the metric of the NPV of additional consumers revenues that was discussed in TA 10A. In way of summary, that metric calculates the net present value of the stream of rate increases using a discount rate of 7.05%. Thus, drought conditions that occur earlier in the study period would have a greater impact than those that occur in later periods. Figure 10-40 shows these NPV calculations under different drought conditions. The figure shows that drought can have some significant impact on the NPV of rate increases. For example, the 1916 drought conditions show an 8% increase in rates. Drought conditions were modeled as entire 34-year sequences of water years with the "drought year" starting in 2014, thus there are no financial impacts following 2048.

| | |
|---|---|
| K19/C25/750 (Preferred) | $10,605 |
| 1912 Drought | $11,320 |
| 2007 Drought | $11,012 |
| 1916 Drought | $11,472 |
| 1918 Drought | $11,357 |

**Figure 10-40: NPV of Rate Increases Under Various Drought Conditions**

In order to test the impact on the debt/equity ratio of potential drawdowns on retained earnings (in a similar vein to the analysis performed by MH), we calculate D/E ratios assuming no rate increases beyond those found under base drought conditions. Figure 10-41 compares the D/E ratio through 2047 across a number of different drought conditions.

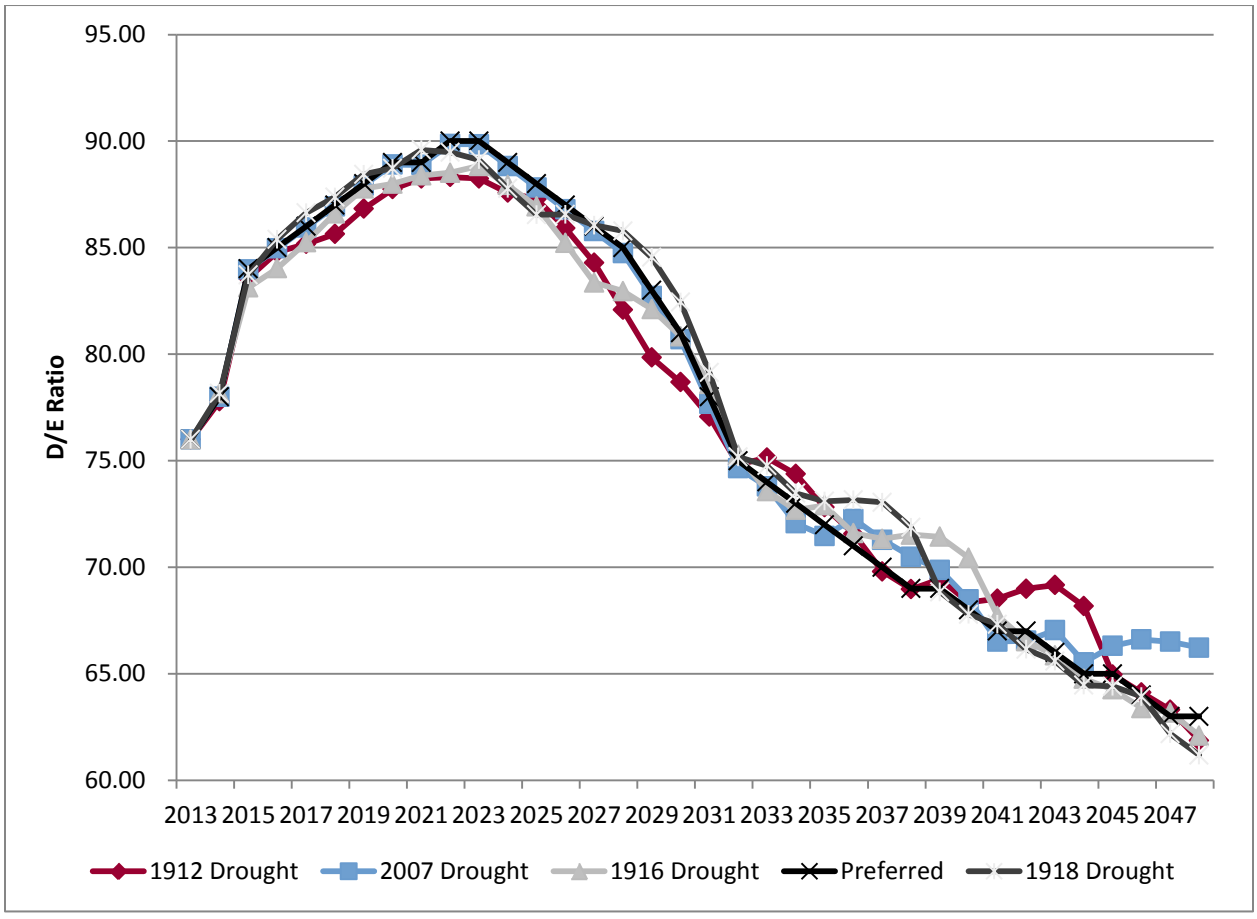


**Figure 10-41: Debt/Equity Ratios Assuming No Additional Rate Increases During Drought**

The figure shows the trajectory of retained earnings among the different drought conditions converges to the 75% target in 2032. The 1918 drought has the most negative impact during the pre-2032 period, but it is only incrementally higher than the D/E ratios found in the preferred plan. Other drought conditions show increases in the D/E ratio in the post-2032 period, but ratios do not exceed the 75% target except for a single year under 1912 drought conditions.

### C. Summary

Overall, our analysis of drought conditions show that rate increases required to maintain the 75/25 D/E target are modest in terms of annual rate increases during the 2013-32 period, though they do reinforce the finding that rate increases under the Preferred plan are highest among the development plans during the 2013-2032 time period. However, different drought conditions will increase the NPV of rate increases relative to base conditions, and these increases can be significant under certain conditions. Finally, in the post-2032 period, drought conditions do not markedly impact retained earnings, which indicates that drought (as measured by the different drought scenarios provided by MH) is not an extreme risk factor in terms of its impacts on retained earnings.

# IV. Analysis of Alternative Development Plans

MH provided economic results for three alternative development plans: (1) A "LCA No New Generation" plan with a demand side management (DSM) revenue impact, (2) a "LCA No New Generation" plan without a DSM revenue impact, and (3) an "All CCGT" development plan that only utilizes combined cycle generating turbines (CCGT), rather than also including combustion turbine generators as found in the All Gas case. These development plans are extensively discussed in Technical Appendix 9B.

For the work in this Technical Appendix, we only examine the LCA No New Generation case. MH supplied information to LCA that also modeled the LCA No New Generation Plan with a Domestic effect. Since Technical Appendix 10B is a financial analysis and thus includes all the costs of producing and delivering electricity, it was not necessary to examine the Domestic Effect issue in this Appendix. This is consistent with the discussion of the Domestic Effect described in TA 9B. The All CCGT case had very similar economic impacts to the All Gas case, thus the incremental financial change of that case would be very small and was not analyzed.

## A. Financial Modeling Assumptions

MH did not provide financial analysis with the new development plans. As in the last section, we applied the spreadsheet model that was utilized in Technical Appendix (TA) 10A in conjunction with the economic data that was extensively discussed in TA 9B. Unlike the drought analysis above, we had to make additional adjustments to our model to examine the alternative case. Though our spreadsheet model is an approximation to the financial modeling that would otherwise be conducted by MH, it does provide useful results for review and analysis.

In order to adapt the economic data to the financial modeling framework, we had to make certain assumptions. First, we utilized the All Gas financial modeling results as a base and calculated differences from that development plan to determine the incremental differences that would be applied to our financial spreadsheet model for the LCA No New Generation plan. Second, we only included economic results through 2061/62, which is the end of the financial modeling study period. Third, for adjustments to net revenues, we compared the net revenues totals in Appendix 9.3 of

the filing for the All Gas plan with the comparable dataset provided for the LCA No New Generation plan and calculated a difference in net revenues that was input to the financial modeling. Fourth, for adjustments to costs, we included (a) fixed operating and maintenance (O&M), and (b) the DSM capital costs, which were assumed to be expensed. Fifth, for depreciation and amortization expense, we assumed a 30-year life and applied a straight-line depreciation assumption to the non-DSM capital cost difference between the LCA No New Generation and All Gas case.

Finally, the finance expense estimates for the non-DSM capital expenditures were calculated in the following manner: (a) differences in the non-DSM capital costs between the All Gas and LCA No New Generation were calculated for each year (b) these differences were assumed to be financed through 20 year debt (c) the outstanding net debt for each year's differences was calculated and added to the net debt balances of the All Gas plan to calculate net debt levels for the LCA No New Generation plan (d) a ratio of the two net debt estimates was calculated for each year and applied to the All Gas finance expense in order to calculate an adjustment to the All Gas finance expenses. For example, the All Gas net debt level in 2040 is $16.6 billion while for the LCA No New Generation plan the figure was estimated to be $15.6 billion. This ratio (94%) was applied to the All Gas finance expense to calculate a finance expense approximately 6% lower for the LCA No New Generation plan in that year.

### B. Rate Impacts of LCA No New Generation Case

Given the above assumptions, we applied our financial spreadsheet to calculated the "additional general consumers' revenue" levels that would be required to meet the financial targets discussed in TA 10A. Figure 10-42 compares the rate impacts of the LCA No New Generation plan to the other development plans in terms of "even-annual" increases.

| Plan # | Development Plan Short Name | Even-Annual Rate Increases (2012/13 to 2031/32 | Even-Annual Rate Increases (2012/13 to 2061/62 | Cumulative Nominal Rate Increases at 2031/32 | Cumulative Nominal Rate Increases at 2061/62 |
|---|---|---|---|---|---|
| 1 | All Gas | 3.43% | 2.07% | 90% | 176% |
| 7 | Gas/C26 | 3.86% | 1.72% | 105% | 134% |
| 2 | K22/Gas | 3.49% | 1.77% | 92% | 140% |
| 4 | K19/Gas/250 | 3.42% | 1.80% | 90% | 143% |
| 13 | K19/C25/250 | 3.98% | 1.50% | 109% | 111% |
| 12 | K19/C31/750 | 3.80% | 1.50% | 102% | 111% |
| 6 | K19/Gas/750 | 3.50% | 1.79% | 92% | 143% |
| 14 | K19/C25/750 Preferred Plan | 3.95% | 1.44% | 108% | 106% |
| -- | LCA No New Generation | 3.38% | 1.87% | 88% | 148% |

**Figure 10-42: Rate Increases by Development Plan under Reference Conditions**

Except for the last row, Figure 10-42 is identical to Figure 10-18 of TA 10A. Based on the even-annual metric, the LCA No New Generation development plan features the lowest rate increases through 2031/32 but shows higher rate increases through the entire study period for all plans except the All Gas plan.

Similar to the work in TA10A, we also calculated the net present value (NPV) of the annual rate increase amounts (beyond approved rate levels) that underlie the calculations found in the above figure. Figure 10-43 shows the NPV calculations assuming use of 7.05% as a discount rate.

| | NPV |
|---|---|
| All Gas | $11,208 |
| K22Gas | $10,834 |
| Gas C26 | $11,107 |
| K19 Gas 250 MW | $10,452 |
| K19 C25 250 MW | $10,885 |
| **K19 Sales C25/750 MW (Preferred)** | **$10,605** |
| K19 Imp C31 750 MW | $10,861 |
| K19 Imp Gas 750 MW | $10,627 |
| **LCA No New Generation** | **$10,238** |

**Figure 10-43: NPV of Rate Increases by Development Plan, 50 Year**

The figure shows that under this metric, the LCA No New Generation Case shows the lowest rate increase over the study period. In similar vein to the discussion found in TA 10A, the values are close, especially when one considers the length of the study period. For example, the difference between the K19 Gas 250 MW Development Plan, which was the plan with the lowest NPV of rate increases discussed in TA 10A, and the LCA No New Generation plan is approximately 2%. However, differences between the LCA No New Generation plan and other development plans, such as All Gas or Gas C26, are more significant.

As a final analysis of the rate impact of the LCA No New Generation plan, we replicate the data found in Figure 10-26 in TA 10A and include the analogous calculations for the new plan. The above analysis showed that in terms of overall rate increase impacts, the LCA No New Generation plan fares the best. It is also instructive to examine the rate per MWh in terms of revenue requirements after incorporating the lower load levels found in the LCA No New Generation plan. Figure 10-44 shows the $/MWh paid by domestic ratepayers for the LCA No New Generation plan compared to the other development plans.

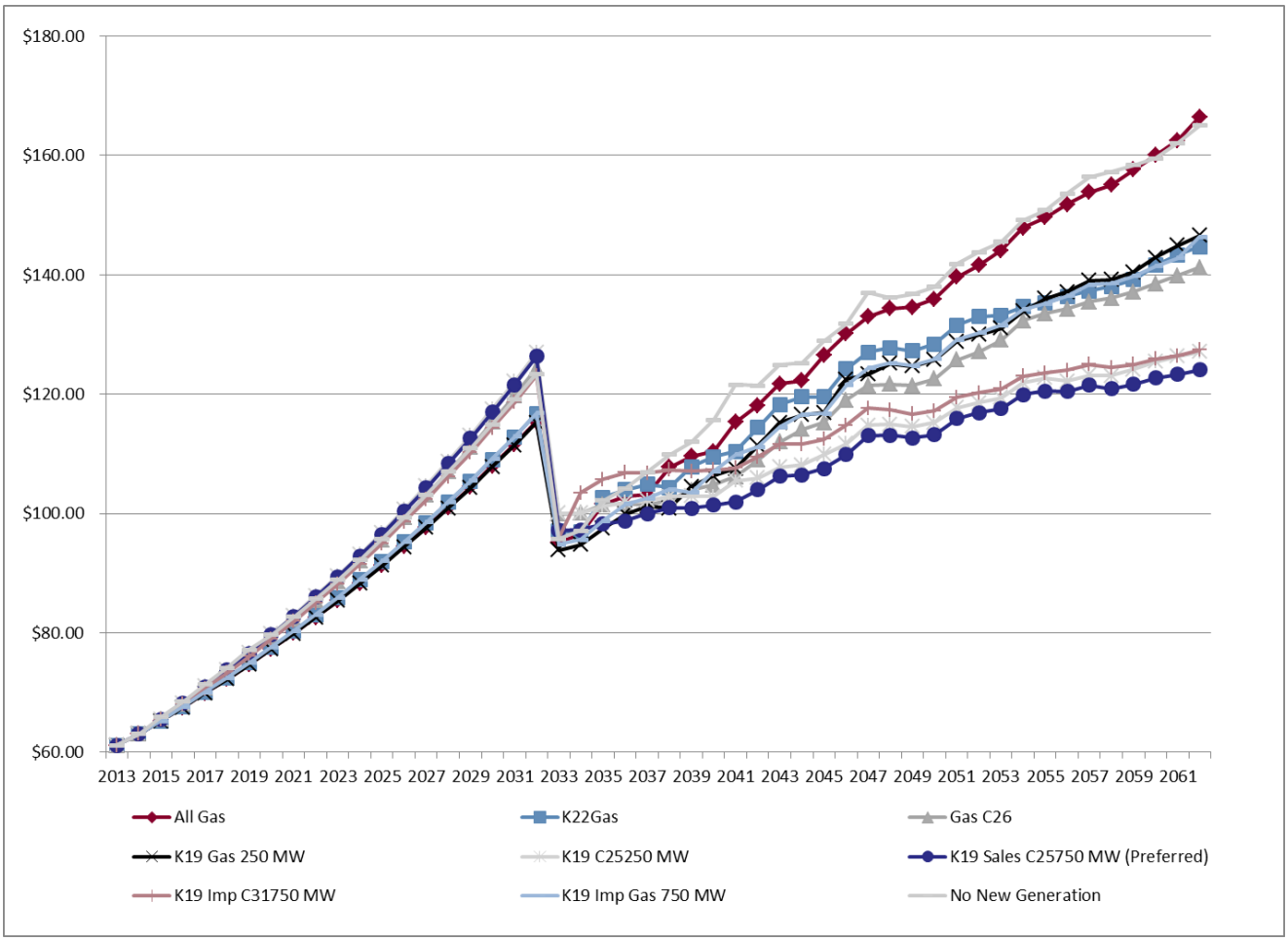


**Figure 10-44: Domestic Energy Sales Revenue @ Meter per MWh under Reference Conditions**

The figure shows that through the initial part of the study period (where the D/E target ratio is applied), the cost per MWh paid by domestic ratepayers for the LCA No New Generation case is comparable (and slightly lower than the Preferred plan). This is the case despite use a lower amount of MWh in the denominator. Following this period, costs for the LCA No New Generation plan rise mostly due to the cost of the DSM capital costs that were assumed to be expensed. However, it is important to note that the above cost figures do not account for the full lifetime benefits of the LCA No New Generation plan. For example, there are energy efficiency savings that will continue after the study period that are not included in the above, but the full costs underlying these savings are included in the above analysis.