Application of Short Run Marginal Cost (SRMC) Test to Rates

Report for 2024

Refiled August 15, 2025

NON-CONFIDENTIAL

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APPENDICES

1.0 BACKGROUND

In its Order in the Generic Rate Design hearing dated August 1, 2003, the Nova Scotia Energy Board (Board, NSEB) directed Nova Scotia Power Incorporated (NS Power, Company) to:

> …perform the SRMC test for all of its above and below-the-line rates. NSPI's report in this regard should describe the methodology it has followed in calculating short run marginal costs as well as the results of the test. This report should be filed by April 30, 2004 and annually on April 30 thereafter.[1]

During that hearing, Board Counsel's consultant, Dr. John Stutz, defined the Short Run Marginal Cost (SRMC) test as a check to determine whether the average revenue per kWh, exclusive of revenue from customer charges, is equal to or greater than the average marginal energy cost. An excerpt from Dr. Stutz's testimony discussing the SRMC test is attached as **Appendix A**.

In its letter dated June 6, 2008, the Board directed NS Power to file a supplementary report, which would provide revised SRMC test results for the years 2003 through 2006. The information was requested to provide consistent comparisons from year to year by correcting prior transmission loss adjustments, accounting for the value of interruptibility and the exclusion of non-electric revenue from the unmetered class. The Board also directed NS Power to include estimates of "inefficient usage" that could result from rates that are below SRMC. NS Power responded to these directives in a supplementary report filed on August 1, 2008.

In a letter dated December 3, 2009, the Board directed NS Power to include information in future SRMC reports on how the SRMC is determined, the estimated percentage of time that coal, oil and gas drive the SRMC, and the degree to which these contributions are driven by environmental requirements, including renewable sources of generation.

In a letter dated November 26, 2010, the Board further directed NS Power to make certain changes to the SRMC test recommended by Board Counsel's consultant Multeese Consulting Inc.

[1] M05002, NSUARB-NSPI P 878, NSUARB Order, August 1, 2003.

(Multeese) in its SRMC memorandum dated August 27, 2010. The changes were to include the revenue adjustment mechanisms of the Demand Side Management (DSM) Cost Recovery Rider (DCRR) and the Fuel Adjustment Mechanism Actual Adjustment (FAM AA) and Fuel Adjustment Mechanism Balance Adjustment (FAM BA).

In a letter dated July 23, 2014, the Board suspended reporting on SRMC comparisons with the Mersey System Rate and the Load Retention Tariff (LRT). The Board also directed NS Power to review Multeese's recommendation that going forward the SRMC test be conducted based on the system load that excludes the LRT load. In its letter dated January 12, 2015, NS Power confirmed its support for Multeese's recommended approach and has applied it for the purposes of SRMC tests going forward.

In its letter dated June 6, 2016, the Board confirmed that the 1P-RTP rate should be excluded from the SRMC test. The Board also confirmed that the modified approach for SRMC comparison of the Shore Power rate based on the average on-peak marginal cost in the service season from April to November, as proposed by NS Power in its 2015 SRMC Report, is appropriate for future analysis.

In its letter dated July 12, 2019 (M09192) the Board directed NS Power to review the issue of volatility in the differential between the average unit revenues and marginal costs and provide the Board with its analysis regarding this large and consistent variance between the average unit revenue and the average marginal cost.

In its letter dated July 30, 2020 (M09701) the Board stated that based on NS Power's analysis, the variance between the average unit revenue and the average marginal cost appeared to be due to non-fuel fixed costs being included in the revenue amounts while marginal costs only reflected the marginal fuel costs. The Board directed NS Power to continue to include a graphical representation of unit revenues separated into fuel costs, fixed costs, and the average marginal cost adjusted for line losses, in future SRMC reports.

In its letter dated July 14, 2023 (M11110) the Board accepted NS Power's explanation that the reasons why the Residential Time-of-Day (TOD) and Large Industrial rate classes failed the 2022 SRMC test and the four Time-varying Pricing (TVP) tariffs failed the test only during the non-critical periods was due to the sharp increase in marginal costs driven by high commodity prices caused by a worldwide inflationary pressures and geopolitical events.

The Board directed NS Power to monitor future SRMC test results for the rate classes that had failed in 2022 stating that if the same rate classes continued to fail the test a review of their rate design might be warranted.

In its letter dated May 27, 2024 (M11683), The Board provided as follows:

> The Board notes that the price elasticities used in the model, and described in Appendix C, are based on American data collected in the 1980s and 1990s and generally for summer and dual peaking utilities. Further, in the decades since these elasticities were estimated, there have likely been substantial behavioural and environmental changes. The Board continues to encourage NS Power to evaluate its price elasticities to ensure they accurately reflect current consumer behaviour and substitutes reflective of the current Nova Scotia context.

NS Power has evaluated the price elasticities it has used. Please refer to section 2.1 for discussion of this matter.

2.0 METHODOLOGY

The SRMC test involves the following steps:

Determine the average marginal cost (over 8784 hours in 2024) at the transmission delivery level. In calculating this marginal cost, the effects of exports and load served under the Extra Large Industrial Active Demand Control (ELIADC) Tariff , the successor to the LRT, are removed from the net system load. The 2024 marginal cost of 8.122 cents per kilowatt hour is calculated based on the fuel, incremental heat rate, and variable operating and maintenance (O&M) costs of the unit serving the next megawatt (MW) for each hour.[2]

(i) Account for distribution line losses by increasing the marginal cost at the transmission level by the average distribution energy losses for those classes which are served at the distribution level. This is done to establish the average annual marginal cost by class at the point of consumption.

(ii) Determine the average annual unit revenue for each class by dividing the appropriately modified actual annual revenues by the actual annual kilowatt hours (kWh) of energy sold.

(iii) Compare the unit revenues from step (iii) to the average marginal costs from step (ii). If the class unit revenue is lower than its average marginal cost, the class fails the SRMC test.

(iv) For classes which fail the test, calculate estimates of inefficient usage by applying price elasticities to the actual annual gigawatt hours (GWh) sales reported for each class.[3]

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[2] The SRMC test is designed to compare unit revenues and marginal costs as measured in cents per kWh. The marginal cost, normally expressed in $/MWh, has been converted to cents/kWh.

[3] NS Power utilized price elasticity of -0.15 applied in its SAE load forecast model from the 2024 Load Forecast Report (M11689) for the Domestic, Small General, and General rate classes. For all other rate classes, a range of short-run price elasticities provided in a report to the California Energy Commission, included as **Appendix C** to this report, was applied. The estimates of inefficient usage must be interpreted with caution because elasticity estimates can differ by region.

(v) The following formula is used:

Δ q = q x price elasticity x Δ price / price

Where:

Δ q – Is the estimated inefficient usage of a rate class

q – Is the annual kWh sales to a rate class

Price Elasticity – Is the percent change in kWh consumption per 1 percent increase in price

Δ price – Is the difference between unit revenue (as determined in step (iii) above) and unit marginal costs estimated for a rate class (step (ii))

Price – unit marginal costs estimated for a rate class (step (ii))

2.1 Review of Price Elasticities

In the 2024 Load Forecast Report[4] NS Power compared the price elasticity of -0.15 used in the statistically adjusted end use model to the elasticities estimated as part of the TVP evaluation, and found the value of -0.15 to be reasonable for modelling the impacts of price on energy sales.

In 2024, there was no inefficiency in the usage due to Marginal Cost being below the unit Revenue cost. The elasticity comes into play when the unit Revenue is below the Marginal cost. NS Power will continue to monitor the elasticity value and will incorporate any updates coming out of the annual Load Forecast Reports.

[4] M11689 – NS Power, 2024 Load Forecast Report, Section 4.5, pages 51-53. April 30, 2024.

3.0 RELATIONSHIP BETWEEN AVERAGE COST BASED RATES AND ACTUAL SHORT RUN MARGINAL COSTS

SRMC test results are determined by comparing appropriately modified average unit revenues for each rate class to actual marginal costs, adjusted for class distribution line losses. The link between these two sets of numbers is not direct. The test outcome is affected by timing differences between regulatory ratemaking and changes in average annual cost of service, as well as fluctuations in the differential between average and marginal unit fuel costs.

Changes in annual unit revenues are primarily driven by changes in rates.[5] Most rates are set based on a forecast rather than actual average costs[6]. The majority of rates,[7] referred to as base cost rates, are set in General Rate Applications (GRA) or Base Cost of Fuel (BCF) Applications. The rate setting process allows class revenues to deviate from class cost of service as determined through the Cost-of-Service Study (COSS). These deviations are measured as the ratio of revenues to costs (R/C). The R/C ratios typically indicate recovery of between 95 percent and 105 percent of cost. However, revenue responsibilities of some rate classes may be set by the Board at R/C ratios falling outside of this range. Since 2013, base cost rates have been set through implementation of multi-year rate plans which, aside from establishing rate changes for a few years in advance, also smooth them on an annual basis. The smoothing of rates has the effect of decoupling test year revenues from fluctuations in test year cost of service during the rate plan. Further, the capping of non-fuel rates in the 2023/2024 GRA resulted in rates being set lower than the prospective test year costs. For the above reasons, the annual unit revenues paid by customers can significantly vary from actual unit cost of service incurred by the utility.

Changes in actual unit short-run marginal costs are subject to different dynamics than those of actual unit average cost of service. In the long-run, when the costs of all factors of production are

[5] Another factor of a lesser significance are changes in monthly billing determinants, such as non-coincident demands and energy sales distribution by energy blocks, from one year to the next.
[6] The exception are the FAM AA/BA riders which are designed as true ups of the BCF rate components.
[7] The exceptions are the annually adjusted rates which are set outside of the GRA framework. Currently two AARs, Generation Replacement and Load Following (GRLF) and Shore Power Rates are subject to the SRMC test.

variable, a positive correlation between marginal costs and average costs is expected, as well as a positive correlation between marginal costs and unit revenues. However, in the short run, such as on an annual basis, there can be significant departures in actual unit marginal costs from actual unit average costs or actual unit revenues. This happens because the utility's fuel costs incurred in serving incremental system load are much more volatile than the total utility fuel costs or total revenues. The utility's unit generation costs are determined by the amount of power produced by individual generators and their unit cost. Due to the economic dispatch order followed by electric utilities in their generation process, the generation mix used to meet demand of incremental system load exhibits more volatility in response to changes in the total system load and market fuel pricing than the total generation mix. This may lead to more volatility in the average annual marginal generation unit costs compared to the average annual generation unit costs.

In summary, the relationship between average-cost-based rates and the SRMC is not direct. Both unit revenues and SRMC can fluctuate from average actual cost of service; each for different reasons. The dynamics of these interactions can be complex and can produce diverse SRMC results on an annual basis. These interactions should be analyzed and understood before rate design changes predicated on the SRMC test results are considered. The annual SRMC test results, as shown in **Figure 1**, has fluctuated from year to year in response to changing load and fuel market conditions.

Figure 1. SRMC Test Results

Year	Above-the-Line Rate Classes		Below-the-Line Rate Classes	
	No. of classes	No. that failed	No. of classes	No. that failed
2014	10	0	4	1
2015	10	0	2	0
2016	10	0	2	0
2017	10	0	2	1
2018	10	0	2	0
2019	10	0	2	0
2020	10	0	1	0
2021	10	0	1	0
2022	16	2	2	1
2023	16	0	2	0
2024	16	0	2	0

Note 1. The Shore Power rate class did not see any service uptake in 2020 and 2021 and as a result the SRMC test could not be conducted on this rate class in those years.

Note 2. There were six new TVP Tariffs, which came into effect in June 22, 2021 (M09777) by way of a pilot program with limited enrolment targets. The SRMC test did not include these Tariffs in the 2021 results due to the incomplete annual consumption record available for these classes and the full calendar nature of the SRMC test.

Note 3. The SRMC test results are predicated on the unit revenue with the FAM adjustments as shown in Figure 1.2 of Appendix B.

The SRMC results presented in **Figure 1** should be reviewed considering the SRMC test drivers (system unit revenues, system unit costs and system energy requirements) as summarized in **Figure 2**. **Figure 2** shows volatility in the differential between the average unit revenues and marginal costs.

Figure 2. Trends in annual Energy Requirement, Unit Revenues and Marginal Costs

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	% Change in 2024
	Total System Requirement (GWh) Net of LRT/ELIADC	9,968	10,102	9,837	9,970	10,252	10,342	9,884	9,940	10,178	10,469	10,561	0.9%
Unit Revenue versus Marginal Costs at Customers Meters	Average MC adj for Line losses ($/MWh)	$48.34	$48.85	$45.35	$55.95	$66.43	$56.11	$45.97	$59.31	$128.55	$73.02	$84.05	15.1%
	Average Unit Revenue adjusted for Year Ahead FAM amounts ($/MWh)	$141.99	$138.57	$135.53	$124.06	$146.78	$146.40	$160.75	$163.06	$165.83	$165.17	$188.30	14.0%
	Variance (UR - MC) ($/MWh)	$93.65	$89.73	$90.18	$68.10	$80.36	$90.30	$114.77	$103.75	$37.28	$92.15	$104.25	13.1%
	% Variance of UR from LL-adj MC	194%	184%	199%	122%	121%	161%	250%	175%	29%	126%	124%	-1.7%
	Number of ATL classes failing the SRMC test	0	0	0	0	0	0	0	0	0	0	0	
Average versus Marginal Fuel Costs at Generator's Gate	Average system fuel costs ($/MWh)	$45.49	$48.11	$45.81	$43.16	$55.97	$60.02	$68.07	$76.66	$77.28	$72.03	$94.49	31.2%
	Average marginal costs ($/MWh)	$46.58	$47.07	$43.80	$54.03	$64.21	$54.23	$44.34	$57.36	$124.88	$70.79	$81.22	14.7%
	Variance (MC - AVC) ($/MWh)	$1.10	($1.04)	($2.01)	$10.86	$8.24	($5.79)	($23.73)	($19.31)	$47.60	($1.24)	($13.27)	
	% Variance of MC from AVC	2%	-2%	-5%	20%	13%	-11%	-54%	-34%	38%	-2%	-16%	

Note 1: Unit revenues reflect deferred fuel cost imbalance for future payment under the FAM.
Note 2: In the years 2014-2019 all reported figures are net of the LRT. In 2020-2023 the figures are net of ELIADC.
Note 3: The unit revenue figure of $124.06/MWh in 2017 replaces the incorrectly stated figure of $112.04/MWh in this table of the 2017 and 2018 SRMC Reports due to inclusion of the LRT sales in the average unit revenue.
Note 4: The 2018 Marginal Cost adj for Line Losses figure of $66.43/MWh replaces the incorrectly stated figure of $55.90/MWh in this table in the 2018 SRMC Report.

Note 5: The 2022 Average system fuel costs ($/MWh) figure of $77.28 /MWh replaces the incorrectly stated figure of $93.43/MWh in this table in the 2022 SRMC Report

3.1 Analysis of Variance between Average Unit Revenue and Average Marginal Cost

As discussed above, there are reasons why marginal generation unit costs are more volatile than unit revenues. There are also reasons why unit revenues tend to exceed the unit marginal generation costs in general. **Figure 3** expands the comparison between the unit marginal costs and unit revenues from **Figure 2** by breaking out the unit revenues between the fuel- and non-fuel related components and providing a graphical portrayal of this relationship for the time period when the FAM has been in effect.

Figure 3. Long-term trend in System Unit Revenues and Marginal Costs Net of LRT/ ELIADC.

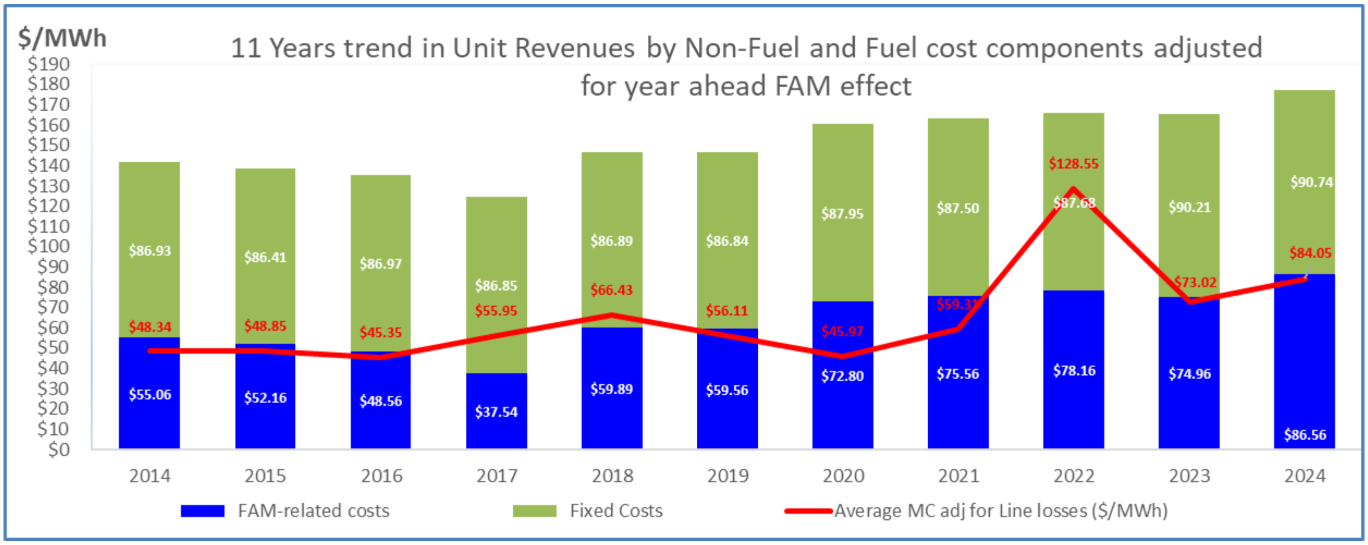

Figure 4. Long-term trend in differential between Marginal Costs and Unit Revenues broken down by fuel and non-fuel components.

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	11 Years Average
Average MC adj for Line losses ($/MWh)	**$48.34**	**$48.85**	**$45.35**	**$55.95**	**$66.43**	**$56.11**	**$45.97**	**$59.31**	**$128.55**	**$73.02**	**$84.05**	**$64.81**
Year over Year % Changes	**-27%**	**1%**	**-7%**	**23%**	**19%**	**-16%**	**-18%**	**29%**	**117%**	**-43%**	**15%**	**11.1%**
Unit Revenues ($/MWh)												
FAM-related costs	$55.06	$52.16	$48.56	$37.54	$59.89	$59.56	$72.80	$75.56	$78.16	$74.96	$86.56	$59.55
Fixed Costs	$86.93	$86.41	$86.97	$86.85	$86.89	$86.84	$87.95	$87.50	$87.68	$90.21	$90.74	$86.20
Total	**$141.99**	**$138.57**	**$135.53**	**$124.39**	**$146.78**	**$146.40**	**$160.75**	**$163.06**	**$165.83**	**$165.17**	**$177.30**	**$145.75**
Year over Year % Changes	**7%**	**-2%**	**-2%**	**-8%**	**18%**	**0%**	**10%**	**1%**	**2%**	**0%**	**7%**	**9.8%**
% Variance from Average MC adj for Line Losses												
FAM-related costs	14%	7%	7%	-33%	-10%	6%	58%	27%	-39%	3%	3%	-8%
Fixed Costs	80%	77%	92%	55%	31%	55%	91%	48%	-32%	24%	8%	33%
Total	**194%**	**184%**	**199%**	**122%**	**121%**	**161%**	**250%**	**175%**	**29%**	**126%**	**111%**	**125%**

Note 1: The figures in the 11 Year Average column under Year over Year % Changes category represent statistical coefficient of variation (Standard Deviation / Mean * 100%).

As shown in **Figure 4**, the unit average marginal costs, aside from following a different annual trend pattern with a higher overall volatility, are also significantly lower than unit revenues in each calendar year. This is because the unit revenues are reflective of total costs of service of the four functional areas of generation, transmission, distribution, and retail. The marginal generation costs used by the Company in the SRMC test reflect, however, only the marginal fuel and generation, operation and maintenance cost. They do not account for fixed costs of any of the four functional areas mentioned above. For that reason, marginal costs typically exceed the average system fuel costs but not the overall unit revenues. In the rare operational circumstance where demand for electricity may approach generation system limits resulting in the use of higher cost generation for an extended period over the year, the average unit marginal fuel costs could exceed unit revenues. This occurred in 2008; however, since that time, in compliance with renewable energy standards and air emissions requirements, NS Power has added a significant amount of must-run, non-dispatchable generation to replace marginal coal-fired generation. This shift in the generation mix had the effect of setting the marginal cost closer to the average system fuel cost level.

The above relationship saw an abrupt change in 2022 with the marginal cost surging above the average system fuel cost due to higher commodity prices caused by geopolitical events in Ukraine. The 2023 results, reflecting a strong decline in marginal costs that year, reverted back to the long-term historical trend.

3.2 Marginal Cost

The average system marginal cost has increased by 14.7 percent from $70.79/MWh in 2023 to $81.22/MWh in 2024. This increase is primarily attributed to changes in generation mix in 2024 to meet various environmental standards and increase in load.

3.3 Base Cost Rates

The 2024 base cost rates were increased in the 2023-2024 GRA proceeding subject to an overall cap of 6.9 percent. The Residential rates increased by 6.8 percent, the General rate increases ranged from 7.0 to 8.5 percent, the Industrial rate increases ranged from 4.8 to 8.5 percent, the Municipal rates increased by 6.1 percent, and the Unmetered rates by 0.2 percent.

3.4 Riders

Starting in 2010, the fuel cost portion of the embedded cost rates has been subject to fuel cost adjustments (FAM AA and FAM BA).[8] Also beginning in 2010, the DSM Cost Recovery Rider (DCRR) was added; however, the DCRR was not been in effect from 2015 to 2022.[9] The DCRR was reinstated in 2023.

3.5 Composite Rates

For the purposes of the second SRMC test, predicated on base cost rates modified for future revenue adjustments, NS Power adjusted the 2024 class revenues for the 2025 FAM AA and 2025 FAM BA amounts, associated with the cost imbalances incurred as of September 2024.

In this report, NS Power has provided two SRMC analyses based on revenues with and without the above adjustments.

[8] In accordance with the Board's Order on the Application by NSP Maritime Link Incorporated for approval of an interim cost assessment for the Maritime Link, Matter M07718, dated November 2, 2017, NS Power refunded FAM ratepayers ML-related depreciation and deferred amortization expenses for the period 2017-2019 through on-bill credits in years 2018-2020. The refunds were treated in the same way as FAM riders for the SRMC test purposes.
[9] Electricity Efficiency and Conservation Restructuring (2014) Act. 2014, c. 5, s. 12.

4.0 SRMC TEST RESULTS

The results of the 2024 SRMC tests conducted on revenues with and without FAM adjustments are shown in **Appendix B**.

All of the tested rate classes passed the two SRMC tests.

Discussion of these results is presented in the next three sections. Section 4.1 discusses the reasons behind changes in average fuel costs and marginal costs and the methodology behind the dispatch of marginal generation in 2024. Section 4.2 discusses SRMC test results for the ATL rate classes. Section 4.3 discusses the challenges of applying this test to BTL rates.

4.1 Variable Generation Costs

The actual unit variable generation fuel cost[10] of the above-the-line rate classes was 20.9 percent above the capped base cost of fuel[11] approved for use in 2024 and 7.2 percent above the 2024 test year base cost of fuel. **Figure 5** below shows the comparison of above-the-line rate actual and test year unit variable cost.

[10] M12121, Exhibit N-1
[11] M10431, P 899- Nova Scotia Power inc. Exhibit N-160, Appendix B - 2023-2024 Proof of Revenue, 2022-2024 GRA Compliance Filing.

Figure 5: Actual and Test year Unit Variable Generation Costs

	2024 Actual	2024 Test Year	
FAM Classes	**Unit Variable Generation fuel cost**	**Capped Base cost of fuel**	**Uncapped Base cost of fuel**
Net Fuel and Purchased Power (Millions)	$958.4	$753.7	$892.3
2024 Sales (GWh)	9,892	9,402	9,872
Unit Variable Cost in Cents/ kWh	9.689	8.016	9.039
% Change from Actual Unit Variable Gen Cost		20.9%	7.2%

Figure 6 below shows the estimated distribution of percentage of time on the margin by type of generation.

Figure 6. Estimated Percentage of Time on the Margin by Type of Generation

Figure 6											
Estimated Percentage of Time on the Margin by Type of Generation											
Type of Generation	**2014 (%)**	**2015 (%)**	**2016 (%)**	**2017 (%)**	**2018 (%)**	**2019 (%)**	**2020 (%)**	**2021 (%)**	**2022 (%)**	**2023 (%)**	**2024 (%)**
Combustion Turbines (CTs) (diesel-fired)	1	1	0	2	3	1	0	0	3	1	0
Imports	7	0	0	0	0	0	0	0	0	0	0
CTs (nat. gas-fired)	3	3	1	7	6	7	9	2	4	8	4
Baseload (HFO or Nat. Gas - Fired)	13	7	4	9	12	16	14	8	19	29	17
Baseload (Coal-fired)	76	89	94	82	79	76	77	90	74	62	79
Average or Total	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**

NS Power follows an economic dispatch order in hourly operation of its generation fleet, subject to annual environmental constraints of greenhouse gas (GHG) emissions, sulphur dioxide (SO_2), nitrogen oxides (NO_x) and mercury (Hg) emissions.

4.2 SRMC Test for the Above-the-Line Classes

The revenue for ATL rate classes reflects the Board-approved rate increase in 2024. Consistent with the Board's 2008 directive, unit revenues for the Large Industrial Interruptible Rider (LIIR)

class and Unmetered Class have been modified to provide a more valid comparison against SRMC. The supply interruptible credit has been added back to LIIR revenues.
The capital and maintenance portions of unmetered revenue have been removed from the unit revenue to identify the energy portion of class revenue.

All the ATL rate classes pass the SRMC test in 2024.

4.3 Residential Time-of-Day

Most of the energy usage in this class is consumed during the off-peak period, and the rate is designed to encourage this behaviour. Comparing the average annual unit revenue to average marginal cost is not meaningful for specific TOD periods, since the average marginal cost reflects the costs in all hours, while the unit revenues are designed around specific time periods. To make the test meaningful, individual TOD rates are compared to average marginal costs calculated for the hours in which the TOD rates are in effect.

The TOD rate has passed the test under all three rate periods.

4.4 Time-Varying Pricing

The TVP Pilot Program offers two types of tariffs: CPP and Time of Use (TOU) tariffs, available to a limited number of eligible customers in the Domestic Service, Small General and General Classes[12]. The rates in these tariffs are designed to encourage customers to shift energy consumption from peak to off-peak hours when the cost of electricity is lower and to reduce peak load thereby reducing upward pressure on system capacity.

The TVP tariffs, were approved for use to a limited number of customers on June 22, 2021, as a pilot program beginning November 1, 2021. The SRMC test for these classes was conducted for the first time in 2022 Report.

[12] M09777, Board Order, June 22, 2021.

Multi-Unit Residential Building Time-Of -Use (MURB TOU) available to General Class was approved effective November 1, 2024. Due to the partial annual historic usage in 2024 being only available for the MURB Tariff, the Company did not conduct the SRMC test on this tariff.

As is the case with the TOD rate, comparing the average annual unit revenue to average marginal cost is not meaningful for specific time-varying periods, since the average marginal cost reflects the costs in all hours, while the unit revenues are designed around specific time periods. To make the test meaningful, individual TVP rates are compared to average marginal costs calculated for the hours in which the TVP rates are in effect.

All of the TOU and CPP rates pass the SRMC tests conducted separately during the season- and time-differentiated pricing periods.

4.5 SRMC Test for the Below-the-Line Classes

BTL rates have been developed based on the operating capabilities and costs associated with serving large customers. Some have self-generation and/or process storage and abilities to shift load or interrupt their consumption for supply or economic reasons.

4.6 Generation Replacement and Load Following (GRLF)

This tariff is available to customers who own generation. The rate does not include a fixed cost component and is provided on a “best-efforts” basis.

The tariff is made up of two separate rates: load following (LF) and generation replacement (GR). The LF rate is set based on the forecast average annual marginal cost while the GR component is based on actual hourly marginal costs.

In 2024, the GRLF Tariff passed the SRMC test. The actual GRLF unit revenue for 2024 is 9.447c/kWh, 16 percent above the marginal cost of 8.122 c/kWh for that year.

As reported in prior SRMC reports, a comparison of this rate to the marginal cost is of limited value. The GRLF rate is set as a sum of a forecasted average annual system marginal fuel cost and a 0.5 c/kWh adder. The differential between the GRLF rate and the actual marginal fuel cost is primarily due to forecasting assumptions differing from actuals. The forecasted marginal fuel cost was higher than the actual marginal cost thus the GRLF rate passed the SRMC test. Also, the GRLF rate is reviewed on annual basis as part of the Annually Adjusted Rates (AAR) process.

4.7 Shore Power Tariff

Shore Power Service is a seasonal priority interruptible service available to seaports in Nova Scotia from April 1 to November 30. For pricing purposes, the service is differentiated by three voltage service levels of Extra High Voltage (EHV) and High Voltage (HV) transmission and Primary Distribution. The Shore Power rates are flat energy charges made up of two components: fuel cost representing the average annual marginal cost and fixed costs representing non-demand related fixed costs. There is also a transformer ownership credit (TOC) applicable to kilovolt monthly demand.

Comparing the average annual unit revenue under this rate to the average annual marginal cost would not be appropriate because the service is seasonal and cruise ship visits occur during daytime hours. To make the SRMC test meaningful, the unit revenues are compared to the average on-peak marginal cost during the service season from April to November.

In 2024 the Shore Power Tariff passed the SRMC test. The actual Shore Power unit revenue for 2024 is 14.359 c/kWh, 133 percent above the marginal cost of 6.163 c/kWh for that year.

5.0 SUMMARY

In 2024, all rate classes passed the SRMC test.

Excerpt from Evidence of Dr. John Stutz in the Generic Rate Design Hearing 2003

Q. How can one check if rates are set below short-run marginal cost?

A. In checking that rates are set above short-run marginal costs, a useful rule of thumb is that the average revenue per kWh, exclusive of revenue from customer charges, should not be less than the average marginal energy cost. Beyond this simple **Short-Run Marginal Cost (SRMC) Test,** consideration of the role of marginal costs will vary according to the rate being considered.

Q. Please explain the basis for the SRMC test?

A. As I noted earlier, the marginal energy cost is simply the cost of supplying the "last kWh consumed," in a particular hour using available resources (i.e., existing generating equipment or imports). In principle, any ratepayer with usage in that hour could be considered as the consumer of that "last kWh." The SRMC Test simply requires that, on average, a rate produce enough revenue, exclusive of fixed monthly charges, to cover the cost of producing the last kWh. If it doesn't, the rate has not been set above short-run marginal cost.

Q. How should the SRMC test be used?

A. In using the test, it is important to note that there may be good reasons why a rate will fail the test:

- If gas and oil prices are very high and coal prices very low, a cost-based rate (i.e., a rate which meets Requirements 1, 2 and 3 set forth in Section 4) could fail the test.
- A non-cost-based rate adopted on the basis of due discrimination could fail the test. However, offering it could still be beneficial to all ratepayers.

If a rate fails the SRMC Test, it should be carefully examined. Absent an acceptable justification for the failure, such as those described above, the rate should be raised to a level at which it passes the test.

Figure 1.1 2024 Base Cost Rate Revenues with DSM

Short Run Marginal Cost Test and Inefficient Usage Estimate for the Year 2024

(Based on 2024 average annual marginal cost of 8.122 cents/kWh)

	Short Run Marginal Cost Test					Inefficient Usage Estimate				
						Sales	Price Elasticity-of-Demand Range		Inefficient Usage (GWh)	
	Distribution Line Losses as a % of Sales	Total Ave. Line Losses	Unit Revenue net of Base Charge in cents per kWh	MC in cents per kWh	% variance	(GWh)	Upper Bound	Lower Bound	Lower Bound	Upper Bound
ABOVE-THE-LINE CLASSES										
Residential non-ETS	6.11%	9.11%	17.51	8.62	103.1%	**4,766.1**	-0.15	-0.15	-	-
Residential Time of Day (TOD)										
On-peak	6.11%	9.11%	21.99	9.38	134.3%	**29.2**	-0.15	-0.15	-	-
Shoulder	6.11%	9.11%	17.41	9.02	93.0%	**190.3**	-0.15	-0.15	-	-
Off-peak	6.11%	9.11%	11.33	8.16	38.8%	**67.1**	-0.15	-0.15	-	-
Annual Average	**6.11%**	**9.11%**	**14.39**	**8.62**	**67.0%**	**286.6**	**-0.15**	**-0.15**	**-**	**-**
Residential Time of Use										
On-Peak (Winter)	6.11%	9.11%	31.54	9.38	236.1%	**4.50**	-0.15	-0.15	-	-
Off-Peak (Winter)	6.11%	9.11%	16.87	9.02	87.0%	**11.78**	-0.15	-0.15	-	-
All Remaining Hours (Non-Winter)	6.11%	9.11%	11.14	8.62	29.3%	**13.7**	-0.15	-0.15	-	-
Annual Average	**6.11%**	**9.11%**	19.18	**7.51**	**155.3%**	**29.95**	**-0.15**	**-0.15**	**-**	**-**
Residential CPP										
Critical Peak Hours	6.11%	9.11%	141.68	11.39	1143.8%	**0.2**	-0.15	-0.15	-	-
Non-Critical Hours	6.11%	9.11%	14.99	9.17	63.5%	**12.8**	-0.15	-0.15	-	-
Annual Average	**6.11%**	**9.11%**	17.22	**7.51**	**129.2%**	**13.0**	-0.15	-0.15	-	-
Small General	**5.47%**	**8.47%**	**16.82**	**8.57**	**96.4%**	**370.3**	**-0.15**	**-0.15**	**-**	**-**
Small General (Time of Use)										
On-Peak (Winter)	5.47%	8.47%	34.15	9.33	266.2%	**0.09**	-0.15	-0.15	-	-
Off-Peak (Winter)	5.47%	8.47%	18.48	8.11	127.8%	**0.27**	-0.15	-0.15	-	-
All Remaining Hours (Non-Winter)	5.47%	8.47%	12.67	8.30	52.6%	**0.37**	-0.15	-0.15	-	-
Annual Average	**5.47%**	**8.47%**	**17.53**	**7.47**	**134.8%**	**0.73**	**-0.15**	**-0.15**	**-**	**-**
Small General (Critical Peak Pricing)										
CPP Hours	5.47%	8.47%	144.48	11.38	1169.1%	**0.00**	-0.15	-0.15	-	-
All Remaining Hours	5.47%	8.47%	19.46	9.16	112.4%	**0.1**	-0.15	-0.15	-	-
Annual Average	**5.47%**	**8.47%**	**21.31**	**7.47**	**185.4%**	**0.1**	-0.15	-0.15	**-**	**-**
General Demand	**2.78%**	**5.78%**	**16.30**	**8.35**	**95.2%**	**2,310.3**	**-0.15**	**-0.15**	**-**	**-**
General Demand Time of Use										
On-Peak (Winter)	2.78%	5.78%	27.67	9.71	184.9%	**0.43**	-0.15	-0.15	-	-
Off-Peak (Winter)	2.78%	5.78%	15.25	13.70	11.3%	**1.2**	-0.15	-0.15	-	-
All Remaining Hours (Non-Winter)	2.78%	5.78%	13.05	11.47	13.8%	**1.8**	-0.15	-0.15	-	-
Annual Average	**2.78%**	**5.78%**	**16.41**	**8.35**	**96.6%**	**3.4**	**-0.15**	**-0.15**	**-**	**-**
General Demand CPP										
CPP Hours	2.78%	5.78%	153.00	11.36	1247.1%	**0.01**	-0.15	-0.15	-	-
All Remaining Hours	2.78%	5.78%	11.48	8.74	31.4%	**0.9**	-0.15	-0.15	-	-
Annual Average	**2.78%**	**5.78%**	**15.86**	**8.35**	**90.0%**	**0.9**	-0.15	-0.15	**-**	**-**
Annual Average	**2.78%**	**5.78%**	**17.34**	**8.35**	**107.7%**	**0.2**	**-0.15**	**-0.15**		
Large General	**3.00%**	**6.00%**	**14.47**	**8.37**	**73.0%**	**360.4**	**-0.15**	**-0.15**	**-**	**-**
Small Industrial	**2.80%**	**5.80%**	**16.28**	**8.35**	**95.0%**	**256.1**	**-0.15**	**-0.15**	**-**	**-**
Medium Industrial	**2.50%**	**5.50%**	**14.61**	**8.33**	**75.5%**	**491.5**	**-0.15**	**-0.15**	**-**	**-**
Large Industrial Firm	**1.60%**	**4.60%**	**14.10**	**8.25**	**70.9%**	**90.6**	**-0.15**	**-0.15**	**-**	**-**
Large Industrial -Interruptible	**1.60%**	**4.60%**	**13.57**	**8.25**	**64.5%**	**584.7**	**-0.15**	**-0.15**	**-**	**-**
Large Industrial	**1.60%**	**4.60%**	**13.64**	**8.25**	**65.3%**	**675.4**	**-0.15**	**-0.15**	**-**	**-**
Municipal	**1.00%**	**4.00%**	**15.66**	**8.20**	**90.8%**	**117.4**	**-0.15**	**-0.15**	**-**	**-**
Unmetered	**6.30%**	**9.30%**	**16.95**	**8.63**	**96.3%**	**77.3**	**-0.15**	**-0.15**	**-**	**-**
Total ATL						**9,759.5**				

Figure 1.2 2024 Base Cost Rate Revenues with DSM and 2024 FAM Amounts

Short Run Marginal Cost Test and Inefficient Usage Estimate for the Year 2024
(Based on 2024 average annual marginal cost of 8.122 cents/kWh)

	Short Run Marginal Cost Test					Inefficient Usage Estimate				
						Sales	Price Elasticity-of-Demand Range		Inefficient Usage (GWh)	
	Distribution Line Losses as a % of Sales	Total Ave. Line Losses	Unit Revenue net of Base Charge in cents per kWh	MC in cents per kWh	% variance	(GWh)	Upper Bound	Lower Bound	Lower Bound	Upper Bound
ABOVE-THE-LINE CLASSES										
Residential non-ETS	6.11%	9.11%	18.66	8.62	116.6%	**4,766.1**	-0.15	-0.15	-	-
Residential Time of Day (TOD)										
On-peak	6.11%	9.11%	24.49	9.38	161.0%	**29.2**	-0.15	-0.15	-	-
Shoulder	6.11%	9.11%	19.92	9.02	120.8%	**190.3**	-0.15	-0.15	-	-
Off-peak	6.11%	9.11%	12.64	8.16	54.8%	**67.1**	-0.15	-0.15	-	-
Annual Average	**6.11%**	**9.11%**	**14.51**	**8.62**	**68.4%**	**286.6**	**-0.15**	**-0.15**	**-**	**-**
Residential Time of Use										
On-Peak (Winter)	6.11%	9.11%	35.79	9.38	281.4%	4.5	-0.15	-0.15	-	-
Off-Peak (Winter)	6.11%	9.11%	18.39	9.02	103.9%	11.8	-0.15	-0.15	-	-
All Remaining Hours (Non-Winter)	6.11%	9.11%	13.35	8.62	55.0%	13.7	-0.15	-0.15	-	-
Annual Average	**6.11%**	**9.11%**	30.24	**13.25**	**128.2%**	**29.9**	**-0.15**	**-0.15**	**-**	**-**
Residential CPP										
Critical Peak Hours	6.11%	9.11%	171.24	11.39	1403.3%	0.2	-0.15	-0.15	-	-
Non-Critical Hours	6.11%	9.11%	16.15	9.17	76.1%	12.8	-0.15	-0.15	-	-
Annual Average	**6.11%**	**9.11%**	18.37	**13.25**	**38.6%**	**13.0**	-0.15	-0.15	-	-
Small General	**5.47%**	8.47%	**17.51**	**8.57**	**104.5%**	**370.3**	**-0.15**	**-0.15**	**-**	**-**
Small General (Time of Use)										
On-Peak (Winter)	5.47%	8.47%	34.84	9.33	273.6%	0.1	-0.15	-0.15	-	-
Off-Peak (Winter)	5.47%	8.47%	19.17	8.11	136.3%	0.3	-0.15	-0.15	-	-
All Remaining Hours (Non-Winter)	5.47%	8.47%	13.36	8.30	60.9%	0.4	-0.15	-0.15	-	-
Annual Average	**5.47%**	**8.47%**	**18.22**	**13.17**	**38.3%**	**0.7**	**-0.15**	**-0.15**	-	-
Small General (Critical Peak Pricing)										
CPP Hours	5.47%	8.47%	145.17	11.38	1175.2%	0.0	-0.15	-0.15	-	-
All Remaining Hours	5.47%	8.47%	20.15	9.16	119.9%	0.1	-0.15	-0.15	-	-
Annual Average	**5.47%**	**8.47%**	**22.00**	**13.17**	**67.0%**	**0.147**	-0.15	-0.15	**-**	**-**
General Demand	**2.78%**	5.78%	**17.48**	**8.35**	**109.4%**	**2,310.3**	**-0.15**	**-0.15**	**-**	**-**
General Demand Time of Use										
On-Peak (Winter)	2.78%	5.78%	28.86	9.71	197.1%	0.4	-0.15	-0.15	-	-
Off-Peak (Winter)	2.78%	5.78%	16.43	13.70	19.9%	1.2	-0.15	-0.15	-	-
All Remaining Hours (Non-Winter)	2.78%	5.78%	14.24	11.47	24.1%	1.8	-0.15	-0.15	-	-
Annual Average	**2.78%**	**5.78%**	**17.59**	**8.35**	**110.7%**	**3.4**	**-0.15**	**-0.15**	**-**	**-**
General Demand CPP										
CPP Hours	2.78%	5.78%	154.18	11.36	1257.5%	0.0	-0.15	-0.15	-	-
All Remaining Hours	2.78%	5.78%	12.66	8.74	44.9%	0.9	-0.15	-0.15	-	-
Annual Average	**2.78%**	**5.78%**	**17.04**	**8.35**	**104.2%**	**0.9**	**-0.15**	**-0.15**	**-**	**-**
Large General	**3.00%**	6.00%	**15.83**	**8.37**	**89.2%**	**360.4**	**-0.15**	**-0.15**	**-**	**-**
Small Industrial	**2.80%**	5.80%	**17.31**	**8.35**	**107.4%**	**256.1**	**-0.15**	**-0.15**	**-**	**-**
Medium Industrial	**2.50%**	5.50%	**15.39**	**8.33**	**84.9%**	**491.5**	**-0.15**	**-0.15**	**-**	**-**
Large Industrial Firm	**1.60%**	4.60%	**15.41**	**8.25**	**86.7%**	**90.6**	**-0.15**	**-0.15**	**-**	**-**
Large Industrial -Interruptible	**1.60%**	4.60%	**14.93**	**8.25**	**80.9%**	**584.7**	**-0.15**	**-0.15**	**-**	**-**
Large Industrial	**1.60%**	4.60%	**14.99**	**8.25**	**81.7%**	**675.4**	**-0.15**	**-0.15**	**-**	**-**
Municipal	**1.00%**	4.00%	**18.22**	**8.20**	**122.1%**	**117.4**	**-0.15**	**-0.15**	**-**	**-**
Unmetered	**6.30%**	9.30%	**17.92**	**8.63**	**107.6%**	**77.3**	**-0.15**	**-0.15**	**-**	**-**
Total ATL						**9,759.5**				

Appendix C
Testimony on The Effect of Restructuring on Price Elasticities of Demand and Supply
August 14,1996

Testimony on
The Effect of Restructuring on Price Elasticities of Demand and Supply

Prepared for the August 14, 1996 ***ER 96*** Committee Hearing

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CALIFORNIA ENERGY COMMISSION

July 17, 1996

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INTRODUCTION

In its February 15, 1996 Committee Order, the ***ER 96*** Committee asked for information on how restructuring may affect price elasticities of supply and demand (Issue III.A.4). This Staff testimony begins with a definition of the concept of price elasticity. A short discussion of existing estimates of demand elasticities follows. The Staff analysis of demand elasticities concludes with a discussion of how restructuring might generally affect the elasticity of demand. A discussion of supply elasticities is followed by a concluding section.

The Concept of Price Elasticity

Estimates of the price elasticity of electricity demand can provide the answer to the following question: if the price of electricity falls, will consumers purchase a lot more or a little more electricity? The concept of elasticity can also be applied to supply curves, though in this context, the question is whether producers will increase the supply of electricity by a little or a lot in response to a change in price. Obviously, the factors that influence demand response to a change in price will be different than those affecting a supply response.

Quantitatively, an estimated price elasticity measures the percentage change in quantity demanded (or supplied) resulting from a 1 percent change in the price of electricity, other factors constant. Since price elasticity estimates are based on a specific price range along a stable demand or supply curve, changes in price outside that range or shifts in demand or supply can alter the elasticity.

Estimates of the Price Elasticity in the Regulated Electricity Market

Existing estimates of demand and supply elasticities are derived from consumer and producer behavior in a regulated electricity market. The prospect of unbundled electricity services, time of use pricing and choice of suppliers via bilateral contracts suggest presently available estimates will have limited meaning as deregulation is implemented. For the immediate future, residential consumers may continue to purchase bundled electricity from their existing utility or an aggregator and thus existing price elasticity estimates may be temporarily useful for one segment of the restructured market.

Most estimates of demand and supply elasticity are based on statistical estimates of demand and supply functions. Good statistical results are dependent on several conditions with respect to the data and techniques employed. Some examples will suffice to illustrate the point. The model to be estimated should not omit theoretically relevant explanatory variables, for example, a model of demand behavior should (at a minimum) include price of the good, the price of substitutes and complements and real income. Often, demographic variables matter, as does information on existing capital stock (square footage of the home, other appliances). Omitting an important variable can bias the coefficient estimates if the omitted variable is correlated with another explanatory variable. In some cases, a variable is omitted for lack of data. In some markets, simultaneous estimation of demand and supply equations is needed so as to properly identify the influence of demand on consumption, as distinct from the influence of supply conditions. This is particularly relevant where supply conditions are changing over the time of the sample data (or over a cross-sectional data set). Statistical problems, such as sampling error, missing data and small samples (or samples with non normal probability distributions) can also be troublesome. It should surprise no one that practice is not ideal, suggesting that statistical estimates be interpreted carefully. Neither should statistical results be dismissed lightly as economists take care to avoid or minimize erroneous results.

Bohi (1981) has surveyed several studies of the demand for electricity employing national data.[1] **Table 1** summarizes the estimates of electricity demand elasticities from these studies; since several studies are reviewed, the results are displayed as a range of estimates for the price elasticity of demand. More recent studies, discussed below, support these estimates.

Table 1
Estimates of Electricity Price Elasticities

	Elasticity Estimates	
	Short-run	Long-run
Residential	-0.06 to -0.49	-0.45 to -1.89
Commercial	-0.17 to -0.25	-1.00 to -1.60
Industrial	-0.04 to -0.22	-0.51 to -{82)

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Most analysts either disaggregate across customer classes or analyze only one customer class. Residential consumers have different motivation (maximizing satisfaction), different responses to a change in price and (prior to deregulation) face different rate structures than do industrial and commercial users (whose goal is to maximize profits). In addition, common sense and economic theory suggest consumers should be more responsive to a change in price over longer periods of time. Consumers have greater opportunity to adjust their behavior and capital stock - appliances, electric motors, coating processes and so forth - to changes in prices and price structures.

In all three customer classes, the table shows that short run demand is price-inelastic (a 1 percent decline in price will result in a less than 1 percent increase in consumption). More recent studies of short-run residential demand elasticities (Branch, 1993 and Hsing, 1994) estimate elasticities of -0.20 to -0.27, well within the range of the studies summarized in **Table 1.**[2]

Bohi, Douglas R., *Analyzing Demand Behavior: A Survey of Energy Elasticitie* Johns Hopkins University Press, Baltimore, 1981.

Branch, E. Raphael, "Short Run Income Elasticity of Demand for Residential Electricity Using Consumer Expenditure Survey Data," *The Energy Journal,* v. 14, no. 4, p. 111-121, 1993; Hsing, Yu, "Estimation of Residential Demand for Electricity with the Cross-Sectionally Correlated and Time-wise

These estimates support the contention that there is a substantial difference between the short-run price elasticity of demand and the long-run price elasticity of demand, regardless of customer class.[3] Certainly the durability of energy-using capital contributes to this result. In the long run, it appears that consumers are very sensitive to a change in price, and that there may be a substantial lag between a change in electricity prices and consumer response (i.e., consumers respond as their refrigerator, heat pump, electric motor, or coating machine wears out). Note however, that the long run response is quite substantial relative to the short run response. It is also worth noting that estimates of the price elasticity of gasoline demand, an energy commodity for which annual consumer (residential) expenditures are roughly the same as electricity and which are also capital dependent (vehicle specific) are -.3 and -1.0 in the short run and long run respectively (Dahl, 1986; Dahl and Sterner, 1991).[4] The estimates of the price elasticity of demand for electricity are comparable to those for gasoline, though possibly slightly higher in the long run.

Table 1 is less clear as· to whether the price elasticity of demand varies across customer classes. Residential consumers are apparently more sensitive to prices in the short run relative to commercial and industrial users. If electricity is a small proportion (say 1 percent or less) of the cost of production for most commercial and industrial users, this result is plausible. However, it appears that commercial users may be most sensitive to price in the long run.

Staff estimated the price elasticity of demand in its energy demand forecasting model by utility service area for ER 94.[5] In general, these estimates are below -.3, and in some cases (depending on year and customer class) are below -.1. These estimates are probably best interpreted as short run price elasticities. In addition, they are consistent with the hypothesis that commercial users are the most sensitive to changes in electricity price of the three customer classes. Additional Staff analysis in progress could shed more light on California-specific estimates of demand price elasticity. Though these estimates are within the range of data in **Table 1,** it is also possible that consumers in California are much less sensitive to changes in electricity prices, compared to the U.S. in general. This conjecture is plausible, given modest space

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Autoregressive Model," *Resource and Energy Economics,* v. 16, p. 255-263, 1994.

In economic analysis, the short run and long run are distinguished by different responses. For our purposes here, the short run could be defined as a period of time in which consumer responseTs limited ~~**to** more or less use of space conditioning (changing the thermostatsettmg), or more or less use **of** Tighimg, with ex1stmg equipment. The long run penod is of sufhc1ent time that consumers can consider more efficient space conditioning equipment, vartal'51e speed motors and fans, and more efhc1ent coating~~ processes. F[redacted]wn[redacted]ort run cou[redacted]or less, [redacted]o hve[redacted] orreifyears (not everyone will replace capital when price rises).

Dahl, Carol,"Gasoline Demand Survey,", *The Energy Journal,* v. 7, no. 1, p. 67-82, 1986; Dahl, Carol and Thomas Sterner,"Analysing Gasoline Demand Elastiticities: A Survey," *Energy Economics,* v. 13, p. 203-210, 1991.

California Energy Demand: 1993-2013, Volume III: The PG&E Service Area Forms, p. 6-2; Volume IV: The SMUD Service Area Forms, p. 6-2.

conditioning loads relative to the rest of the U.S. and the implementation of several programs to improve the efficiency of use by all three customer groups in California.

CHANGES IN DEMAND ELASTICITIES DUE TO RESTRUCTURING

As restructuring proceeds, more and more customers will purchase unbundled services. These will include differentiated products such as different levels of service quality and ancillary services such as load following. The combination of direct access, unbundled services, new rate structures, greater availability of time-of-use (TOU) rates and new market participants (e.g., new suppliers, new energy service companies, aggregators and marketers) may possibly have an impact on the price elasticity of demand or supply. Some potential changes to demand and supply elasticities are discussed below. Electricity industry restructuring **will** affect the price elasticity of demand and supply in other ways that cannot be anticipated with current knowledge.

General principles can provide qualitative guidance as to whether consumers and producers will be more sensitive to a change in price after restructuring occurs. With respect to demand, consumers will be more sensitive to price

- the greater the number of substitutes
- the greater the proportion of the consumer's budget
- the greater the amount of time consumers have to adjust to a change in price.

In the short run, restructuring may not have much effect on consumer behavior, both because consumers have limited short run options for responding to changes in price and also because the market will take some time to implement. If the long run result of restructuring is a competitive market, it is not unreasonable to believe consumers will be well-informed about their consumption choices, most customers will buy electricity and (possibly ancillaries) metered via time of use pricing, energy services companies will provide a full array of conservation options, transmission access will be readily available and transmission constraints will be minimal, and there will be enough suppliers (of energy and energy conservation) that market power will be largely absent.

The regulated market includes some elements of this ideal competitive market. For example, industrial customers whose demand exceeds 500 kW are already on time-of-use metering and some have bargained directly with the utilities for rates more closely aligned with marginal . costs of serving them. There already exists a market for surplus power from the Southwest and Pacific Northwest. There is a small and limited market for energy conservation, though it is growing. In part, this means that more widespread implementation of, for example, time-of-use pricing, will have a smaller impact on the price elasticity of demand for electricity than would otherwise be true.

Competing Suppliers

The act of establishing competing suppliers (more substitutes) will increase the price elasticity of demand faced by individual generation companies (so long as transmission is inexpensive and open access prevails), though its effect on the price elasticity for the entire market demand for electricity is unclear. In the long-run, the stimulus of market forces may result in additional substitutes; self-generation is already one option for large industrial customers and distributed generation (if economic) could allow that option for other end-users.

Bilateral Contracting

The behavior of buyers relying on bilateral contracts is likely to differ from consumers purchasing power from Western Power Exchange (WEPEX). Intuition suggests that buyers in bilateral contracts are probably more sensitive to price, otherwise, bilateral contract buyers would not be willing to incur the cost of negotiating (and enforcing) a contract. There are other potential motivations for a bilateral contract. For example, some buyers may be attracted to bilateral contracts if contracting reduces price risk (or reduces exposure to price volatility). Contracting may also be attractive to buyers who demand a certain level of power quality (higher or lower than that delivered from the Independent System Operator), or other attributes of electricity consumption, that can be more easily contracted for outside purchases from the ISO. These other factors aside, increased bilateral contracting will increase the price elasticity of demand. It is not clear how much electricity will be sold via contracts and whether that share of the market will grow over time.

Unbundling of Electricity

Unbundling electricity into distinct commodities such as energy, reliability or spinning reserve, quality, such as voltage control delivery to customers, could have some interesting effects with respect to the price elasticity of demand. Consider first the market for reliability and quality. It is likely that fees for these services will be smaller than charges for electricity consumption, and thus a much smaller proportion of consumer expenditures than total electricity is now. [6] Other factors equal, this would suggest relatively price inelastic demand for many ancillary services. In addition, it would not be surprising that there are fewer suppliers of reliability and quality than of electrons or that this segment might be served largely via contracts.

Though ancillary fees may be small for most customers, this will not be true of all customers. For example, some industrial and commercial users may have total costs for some services other than electricity equal to (or even higher) than their electricity costs. Such customers are unlikely to be large purchasers of these goods relative to the market as a whole.

At the same time, unbundling of the "single package" service will increase price elasticity because it will increase the number of substitute goods available to consumers. Unbundling will provide consumers with numerous options regarding, for example, voltage control, reliability, energy efficiency services, power management, and billing and metering options. As the number of products customers can choose and as the number of substitutes for those products increase, consumers will be more sensitive to price. However, they will also be purchasing goods not currently available. Thus, unbundling may have conflicting effects on the price elasticity of demand for electricity.

Time of Use Rates

Time-of-use (TOU) rates, where t e kilowatt hour ·charge depends on whether the customer's load is at 3 am or 3 pm, permit prices to be aligned more closely with the marginal cost of supplying electricity. Increased use of TOU rates will allow customers to more closely match the benefits they receive from their service with the cost of that service. This increased use will also increase the efficiency of the generation system. Unlike other capacity constrained industries, such as airlines and phone companies, electricity prices usually do not vary by the time of day for other than large customers. After deregulation of the airline, trucking and railroad industries, all three have been able to improve operating efficiency. This improved use of scarce capital reduced costs and prices to customers. It is impossible to guess how much of an improvement in efficiency in generation and distribution will occur as a result of increased use of TOU rates (nor will all of the efficiency accrue to in-state generators).

Though several utilities have conducted experiments with TOU rates, they have not been implemented on a widespread basis. For example, approximately 3.7 percent of PG&E's residential customers are billed via TOU rates. There have been both technological and economic barriers to widespread TOU rates for residential customers. For the three investor-owned utilities, there are approximately 8.3 million residential customers statewide and residences account for roughly one third of electricity demand. Time of use pricing requires metering capable of recording consumption at peak and off-peak times. Transaction costs for new metering capability are high due to device costs, maintenance costs and meter reading costs. For widespread residential use of TOU pricing to occur, new technologies in the telecommunication and computer industries may need to reduce the transaction cost of this type of pricing.

In California, TOU rates are required for all large electricity customers, specifically, those customers with demand over 500 kilowatts. For example, data from PG&E's 1995 FERC Form No. 1 shows there were, on average during the year, 1,066 customers purchasing power from rate schedule E-20 (service above 999 kW). The Energy Commission database on the 300 largest electricity customers indicates these customers consumed 21,310 GWh in 1992 (slightly more than 13 percent of all electricity sold). Thus, it is reasonable to conclude that a considerable portion of the electricity sold to large customers in California is already priced via TOU rates.

Increased use of TOU rates could increase the overall demand elasticity. TOU rates increase the number of substitutes and options available to consumers. Consumers will face higher peak rates (summer afternoons), relative to current rates, and lower off-peak rates (winter mornings). Consumers will be more sensitive to peak period prices than they are to current rates (i.e., one could think of peak demand as being for a different good), though this is exactly when preferences for electricity use are highest. Consumers may be able to substitute air conditioning during high cost periods vs. low cost periods. There may be some prospects for additional technological developments similar to variable speed motors and fans in HVAC applications. Programmable microchips are inexpensive and it would not be surprising, for example, to see appliance manufacturers produce heating and cooling equipment or refrigerators or electric water heaters that can be cycled at certain times of the day, or possibly integrated house management systems (currently available but not in widespread use). Similar technology could be applied in commercial use and manufacturing, though such applications may be limited.

Satisfaction Worl.G and Bright Line Energy Smvey Analysis

A 1996 survey by Satisfaction Works and Bright Line Energy (SW-BLE), "The Market for Electric Energy in California," provides additional information on customer characteristics. The survey results, which covered 1,300 large California customers, are summarized below. As with any survey, the results should be interpreted with care; the more precise and well-defined the questions are, the more likely the answers are to be a reflection of customers' actual behavior.

This survey shows that 50 percent of the commercial and 56 percent of the industrial customers surveyed are likely to look for new suppliers when direct access is available. However, of the 24 criteria used to evaluate the performance of their electricity supplier, competitive price was ranked 18th by commercial customers and 21st by industrial customers. Customers ranked reliability and customer service related criteria among the top three.

Though electricity price appears to be ranked low, the largest differences between customers' expectations and their perceptions of utility performance are in the areas of price and supplier responsiveness to reducing the customer's energy costs. Forty-five percent of industrial and 49 percent of commercial customers would choose another supplier for a price reduction of 10 percent or less. However, when customers most likely to choose another supplier were offered lower prices or enhanced service, such as guaranteed long term availability of power, backup power capabilities, stable prices, better power quality or custom energy management services to reduce costs, over half preferred enhanced services.

Two plausible interpretations of these results in the context of the price elasticity of demand are sensible. First, it seems clear that commercial and industrial consumers will be highly sensitive to changes in price among competing suppliers. As the earlier discussion pointed out, implications for the demand faced by competing suppliers has little, if any, implications for the price elasticity of market demand, as opposed to the demand curve faced by individual suppliers. Second, customers care, in some cases a great deal, about attributes of electricity consumption other than price.

Restructuring Experience in Other Countries

Studies of other countries that have deregulated electricity provide information on demand elasticity after restructuring.

In Wolfram's (1995) study of market power in the British electricity spot market, she concludes British generators were charging prices higher than their observed marginal costs, but that they had not taken full advantage of the inelastic demand to raise prices to levels predicted by the estimated models. [7] The estimated demand equation yielded price coefficients that indicated demand was almost twice as sensitive to price on winter weekdays. The price coefficients implied price elasticities of approximately -0.1. This indicates that after restructuring in Britain demand was inelastic. These estimates are not comparable to the U.S. data discussed above because Wolfram's data pertains to a daily demand curve.

Lo, McDonald and Le (1990) developed a model for estimating the appropriate time-of-day tariff for managing peak load, in the context of the deregulated UK electricity market. [8] Implicit in their models were elasticities of demand derived from other studies. Their review of previous literature on the UK system concluded that price elasticities of demand were relatively elastic in the long run and relatively price inelastic in the short run, with values ranging from -0.13 to -1.14 for short run and -1.12 to -1.89 for long run. These estimates are similar to the estimates in Bohi's survey, except for the higher estimate of the short run price elasticity.

ELECTRICITY SUPPLY ELASTICITIES

Current Supply Elasticity Estimates

Supply elasticities, per se, do not exist in a regulated retail electricity market. Prices are set beforehand in a regulatory proceeding, and utilities must supply all retail power demanded at the price paid by their franchise customers. Thus, utilities are required to buy or build the power, reliability, ancillary services and transmission necessary to meet retail demand.

Wolfram, Catherine, "Measuring Duopoly Power in the British Electricity Spot Market," presented at Electricity Industry Restructuring: A Research Conference, University of California Energy Institute, March 1996.

Lo, K.L., J.R. McDonald and T.Q. Le, "Time-of-day Electricity Pricing Incorporating Elasticity for Load Management Purposes," *Electrical Power and Energy Systems,* v. 13, no. 4, p. 230-239, 1991.

Supply elasticities currently exist in.the Western wholesale markets, where utilities and marketers compete to sell their "excess" generation in order to gamer contributions to margin for shareholders or for native load customers. Short-term supply does expand as price increases; higher cost thermal units can be turned on or ramped up and generation from further away can pay the transmission charges. In today's market there is a huge band of fossil-fueled generation with very similar costs, so that in the absence of transmission constraints, out-of-state supply of surplus energy is very elastic. Whenever there are transmission constraints, a price increase cannot increase the availability of energy from areas on the other side of the constraint.

A countervailing force in the wholesale market is the role played by hydropower. Availability of very cheap power can swing by a factor of three, depending on which parts of the hydro-producing West are in wet, average or dry conditions. Because the western fossil-based system was built to complement the hydro system, supply elasticities are more volatile and weather-related than might be expected.

Changes in Supply Elasticities Due to Restructuring

Given that FERC open transmission access policies and the creation of an ISO will reduce transmission access constraints, supply elasticities should be higher in the long run. The incentives for operating existing generation will be more market-driven. Also, as a result of emerging direct access, retail customers will be able to participate in the market.

This will not occur overnight. During the transition period, the operation of the competitive transition charge (CTC) may reduce the supply elasticities for power plants that the utilities continue to own. If market prices for energy decrease, the utilities would have less incentive to reduce output at their power plants because they need only cover their variable costs. When the CTC is completed and generators rely on market-based prices or long-term contracts, they will be at risk for the full cost of generation. In the long-term, without guaranteed cost recovery from the CTC or the PBR for the life of a unit, we expect the amount of total generation will shrink. Uncompetitive units will be retired.

Even in a restructured world, some units may not be subject to supply elasticity. Units which are designated as "must-run" will have minimum performance requirements and, as a quid pro quo, cost recovery through a performance-based rate. Even if the market prices fall below operation and maintenance costs, owners of "must-run" generation may have no incentive to reduce output or to cease operating the power plants.

As a result of restructuring, the scope of existing markets would change, and new markets would emerge. Markets will emerge for ancillary services, and the current separate prices for firm and non-firm energy will be replaced. Bilateral contracts, contracts for differences and futures markets will emerge. These will supplement the pool market which includes only day-ahead and hour-ahead deals and the ISO real-time and ancillary services markets. As compared to a pool without these markets, the financial instruments will increase supply elasticities by reducing the investors' risks.

As long as this is a high capital cost industry, we expect generation supply from new resources not to be very elastic compared to other forms of commerce. Long lead times and investors' risk mean that the entry of new generation in response to price increases will be gradual. There will also be public pressures not to let prices rise above current real levels. Only if prices rise substantially above such levels is generation supply expected to be very elastic. If prices do rise, the market response is more complicated than just adding generation. Investments in transmission upgrades or energy efficiency are equally feasible options. [9] Competition among suppliers in retail markets may stimulate new smaller supply options. This should increase the price elasticity of electricity supplies. The extent of such options will depend on the future funding of financing electricity research and development.

Future supply elasticity is dependent on a number of decisions being made about the structure of the new market. For example, in markets with local transmission constraints, supply elasticities will initially be very low. Current plans call for such markets to be largely supplied by power plants subject to "must-run" constraints, thus unable to change their output in response to price changes. Over time, it is hoped that reliability or voltage support services of these power plants will be unbundled from the energy production of these power plants. Ancillary services could be provided in whole or in part by demand-side bidding, by local transmission upgrades, or by building new power plants within areas of transmission constraints. Therefore, the energy production from existing power plants would no longer be "must-run" and would become more responsive to price changes.

Another example comes from ancillary services. Staffs preliminary analysis suggests that PG&E may find that a principal value of its hydro is for spinning reserve rather than for energy sales. The use of hydro for spinning reserve implies a low supply elasticity for spinning reserves. But, hydro is a multi-use resource with many competing demands and PG&E's hydro operations could largely reflect incentives from the planned performance based ratemaking. to be filed at the CPUC this summer.

Research on Elasticities

The University of California Energy Institute (UCEI) is currently doing a market power analysis under contract with the Commission [10] which uses estimates of demand and supply elasticities. UCEI will analyze the fringe firms' supply elasticities in the spot markets under restructuring. The fringe firms are those which have little or no influence on prices and take prices as given, as opposed to dominant firms which may have some influence on price and do not take prices as given. UCEI is considering using a range of market demand elasticities at the end user level. The UCEI contract will use estimates of elasticities of demand for dominant firms to project the extent of market power.

See also Robert Grow's June 18, 1996 ***ER 96 Testimony On Incentives For New Generation*** .

[10] Results will be available in November 1996.

Witness Qualifications
for
BRANDT STEVENS

EDUCATION

Ph.D., Economics, University of California Riverside, 1982
M.A., Economics, University of California Riverside, 1979
B.A., Economics, California State University Fresno, 1974

PROFESSIONAL EXPERIENCE

Dr. Stevens has been employed by the California Energy Commission since 1989. He has been a contributing author to the Fuels Report and the California Transportation Energy Analysis Report. Dr. Stevens is a member of several professional associations. His research has been published in journals such as the *Journal of Environmental Economics and Management, Energy Economics* and *Resource and Energy Economics*. In addition, he has been a manuscript reviewer for journals, including a recent manuscript review for *Contemporary Economic Policy*.

Prior to employment at the Energy Commission, Dr. Stevens held a faculty appointment at Illinois State University in Normal, Illinois.

Witness Qualifications
for
LIONEL LERNER

I am currently (since December 1, 1994) an Electric Generation System Program Specialist I. Previously, I developed assumptions and methods for the capacity expansion and demand conformance processes. My major responsibility is analyzing electricity restructuring issues including market power in deregulated portions of the electricity industry. I also analyze Federal legislation affecting these processes, including the National Energy Policy Act (NEPACT). Prior to this, I was the Commission expert on municipal utility need conformance, and did economic impact analyses for technologies. I did socioeconomic analyses for conservation program EIRs, including BIR on load management standards.

Before coming to the Energy Commission, I reviewed the work of district economist at the Department of Water Resources, and was project manager for a statewide input-output model.

I hold a Ph.D. degree in Political Economy from Johns Hopkins University, Baltimore, Maryland, and an M.A. degree in Economics from the University of Chicago.

CONCLUSION

During the transition to the competitive market, changes in the price elasticity of demand and supply are likely to be small. In the longer term, competition may increase the price elasticity of both demand and supply. Existing estimates of the long run price elasticity of demand already suggest much greater responsiveness to a change in price, in contrast to the short run. Competition is likely to increase substitutes available to consumers. If deregulation in other industries is a good guidepost, competition will create entirely new goods that cannot be imagined now. Few observers of telecommunications could have predicted the availability of call forwarding, caller identification or cellular phones. It seems plausible that restructuring of electricity will have similar effects with respect to demand and supply.

With respect to supply, restructuring will change the scope of existing markets and new markets would emerge. Given that FERC open transmission access and the creation of an ISO will reduce transmission access constraints, supply elasticities should be higher in the long run. The incentives for operating existing generating units will be more market-driven. However, generation supply from new resources would not be very elastic compared with other forms of commerce. Long lead times and investors' risk mean that the entry of new generation in response to price increases will continue to be gradual.