LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information Dated January 8, 2021

Case No. 2020-00350

Question No. 68

Responding Witness: Adrien M. McKenzie

Q-68. Refer to the McKenzie Testimony, page 9 lines 3–25 and 16–19.

a. Current stock market indices have all recovered from the COVID-19 shock and are at or near all-time highs. Explain how this is indicative of a "fundamental shift in investors' risk perceptions.

b. Explain how overall market volatility has increased from prior to the COVID-19 shock and post-COVID-19 market low.

c. Since the stock market indices are at or near all-time highs, explain how the dramatic increase in market value from the market lows from the COVID-19 shock is indicative of an increased perception of risk.

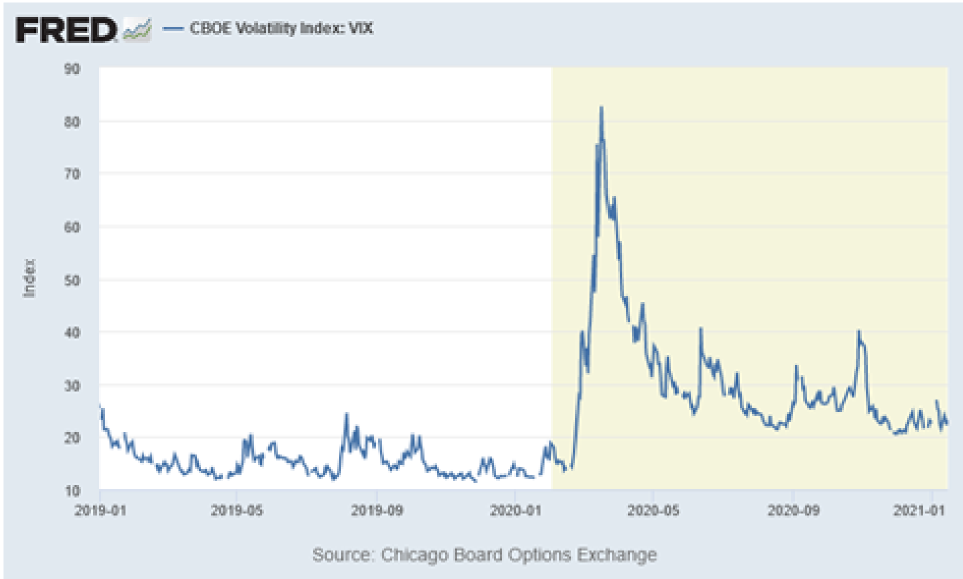
d. Provide evidence that current monetary policy and interest rate environment is going to shift such that the "artificial" nature of the interest rate environment will cease and interest rates will increase to "normal" levels.

e. Explain whether the Federal Reserve has given any indication that it is going to change its current policy path.

A-68.

a. As discussed at page 17 of Mr. McKenzie's testimony, while the broader equity market has recovered from the lows reached in March 2020, utility stocks remain significantly below their previous highs. Coupled with ongoing market volatility, as evidenced by levels of the Chicago Board Options Exchange Volatility Index ("VIX") that remain well above pre-pandemic levels, and the significant increase in utility beta values, this supports Mr. McKenzie's statement that there has been a fundamental shift in investors' risk perceptions.

b. As discussed at page 16 of Mr. McKenzie's testimony, the VIX is a key measure of expectations of near-term volatility and market sentiment recognized in the investment community. The graph below shows the trend in the VIX since January 2019:



As illustrated above, while the VIX has declined significantly since the peak coinciding with the market's precipitous decline in March 2020, expectations of continued volatility remain well above levels prior to the pandemic.

c. See the response to part a.

d. The most recent published projections of the Federal Open Market Committee indicate that the majority of its members expect that the midpoint level of the target range for the federal funds rate will increase from 0.125% to 2.5% over the longer term, which is considered to be five to six years. This twentyfold increase indicates that the Federal Reserve expects to significantly alter monetary policies going forward. As documented at page 60 of Mr. McKenzie's testimony, projections from widely recognized forecasters also support a finding that interest rates are expected to increase substantially from current levels over the near-term.

e. See the response to part d.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 69

Responding Witness: Adrien M. McKenzie / Daniel K. Arbough

Q-69. Refer to the McKenzie Testimony, page 16 lines 25–26 through 18 lines1–7. The stock markets appear to have recovered from the COVID-19 induced sell off and are currently at or near all-time highs.

a. Provide the S&P Global Ratings publications since June 2020.

b. Provide the State Regulatory Evaluations, RRA Regulatory Focus issues published October through December 2020.

A-69.

a. S&P Global Ratings is one of the largest providers of investment information worldwide and publishes an enormous volume of reports on a multitude of topics. Thus, without further specificity LG&E is unable to respond to this question.

b. Attached is the RRA Regulatory Focus: Major Rate Case Decisions - January - September 2020, which RRA published on October 20, 2020. The Companies will supplement this response and provide the RRA report covering awarded returns on equity for the fourth quarter of 2020 and year-end 2020 when the report is available.

S&P Global
Market Intelligence

October 20, 2020
spglobal.com/marketintelligence

RRA Regulatory Focus
Major Rate Case Decisions - January - September 2020

The equity returns authorized electric and gas utilities nationwide edged downward in the first nine months of 2020, which saw less activity than might otherwise have been the case. Several rate case decisions have been postponed until later this year and beyond due to the health and economic crisis triggered by the COVID-19 pandemic that brought the U.S. economy to a near halt. Based on data gathered by Regulatory Research Associates, a group within S&P Global Market Intelligence, the average return on equity authorized electric utilities was 9.50% in all rate cases decided in the first three quarters of 2020, below the 9.65% average for cases in full-year 2019. There were 38 electric ROE determinations in the first three quarters of 2020, versus 47 in full-year 2019.

The average ROE authorized gas utilities was 9.45% in cases decided during the first nine months of 2020 versus 9.71% in full-year 2019. There were 20 gas cases that included an ROE determination in the first nine months of 2020 versus 32 in full-year 2019.

Included in electric ROE average is a decision by the Maine Public Utilities Commission in which the commission reduced Central Maine Power Co.'s ROE by 100 basis points to 8.25% due to imprudence associated with a new billing system. The adjustment is to be lifted when the utility meets all performance benchmarks for all service quality metrics for at least 18 consecutive months after March 1, 2020, and formally demonstrates to the commission that the problems have been resolved. Excluding the 100-basis point penalty would result in a 9.52% average ROE for the first three quarters of 2020.

In addition, the electric ROE average through the third quarter of this year was also weighed down by an 8.20% ROE authorized Green Mountain Power, as calculated under the company's multiyear regulation plan which employs a formulaic approach tied to U.S. Treasuries.

This data includes several limited-issue rider cases. Excluding these cases, the average authorized ROE was 9.44% in electric rate cases decided in the first nine months of 2020, versus 9.64% observed in full-year 2019. The difference between the ROE averages including rider cases and those excluding the rider cases is driven by ROE premiums allowed in Virginia for riders that address recovery of specific generation projects.

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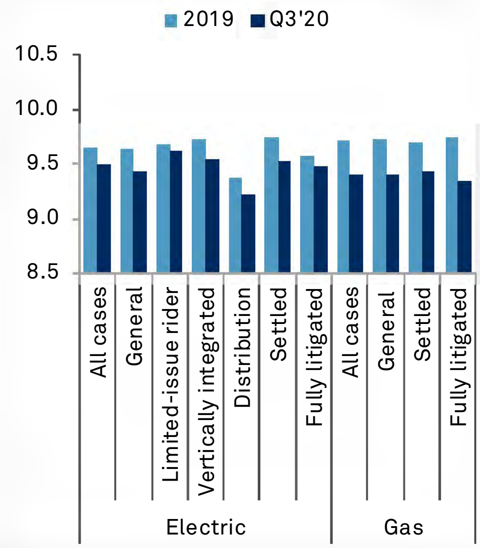
For Detailed Data

Click here to see supporting data tables.

Average authorized return on equity (%)

Dashboard



Electric average	2019	Q3'20	
All cases	9.65	9.50	▼
General rate cases	9.64	9.44	▼
Limited-issue rider cases	9.68	9.62	▼
Vertically integrated cases	9.73	9.54	▼
Distribution cases	9.37	9.22	▼
Settled cases	9.75	9.52	▼
Fully litigated cases	9.58	9.48	▼
Gas average	**2019**	**Q3'20**	
All cases	9.71	9.45	▼
General rate cases	9.72	9.45	▼
Settled cases	9.70	9.53	▼
Fully litigated cases	9.74	9.33	▼
U.S. Treasury	**2019**	**Q3'20**	
30-year bond yield	2.58	1.54	▼

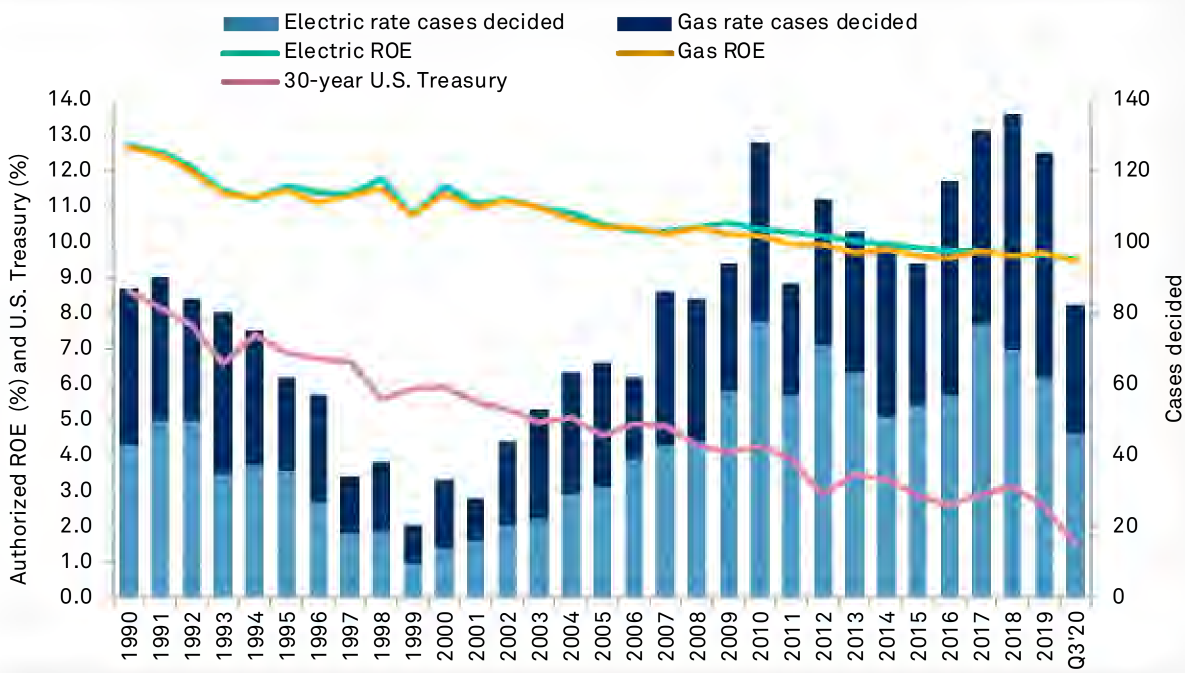
Data compiled Oct. 15, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

In the first nine months of 2020, the median ROE authorized in all electric utility rate cases was 9.44%, versus 9.60% in full-year 2019; for gas utilities, the metric was 9.42% in the first nine months of 2020, versus 9.70% in full-year 2019.

The averages for the first nine months of 2020 are at the lowest levels ever witnessed in the industry, and with the recent interest rate cuts by the U.S. Federal Reserve and current pandemic-induced recession, even lower authorized returns may be on the horizon.

From a longer-term perspective, interest rates, as measured by the 30-year U.S. Treasury bond yield, fell almost steadily from the early 1980s until 2015 or so, placing downward pressure on authorized ROEs. Even though the decline has been less dramatic in the period since 1990, average authorized ROEs fell below 10% for gas utilities in 2011 and for electric utilities in 2014.

Average electric and gas authorized ROEs and number of rate cases decided



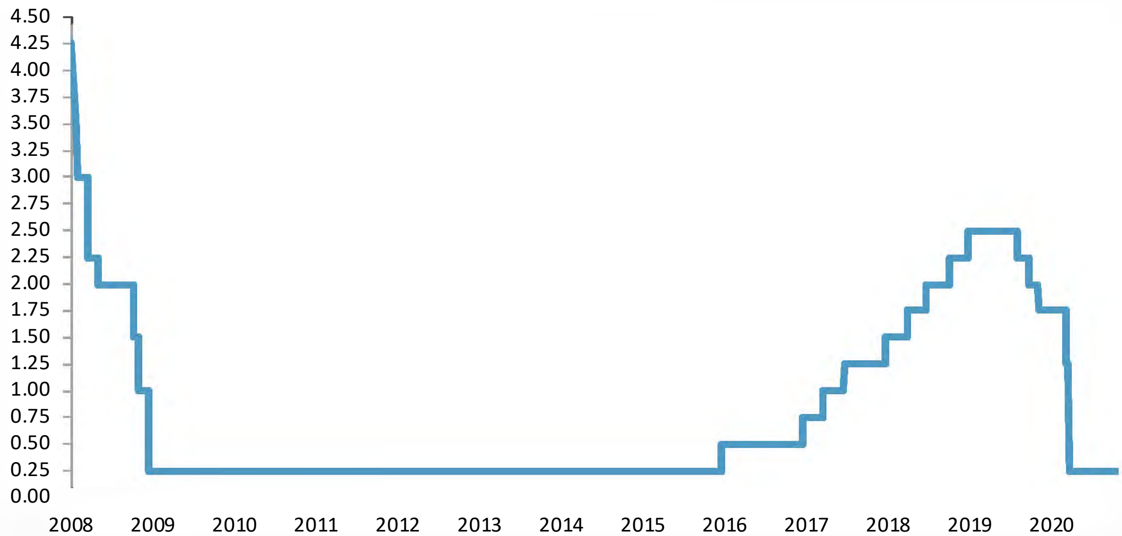
Data compiled Oct. 15, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Since 2010, rate case activity has been robust, with 100 or more cases adjudicated in eight of the last 10 calendar years. This count includes electric and gas cases where no ROEs have been specified; however, withdrawn cases are not included. After reaching an almost 30-year high in 2018, when almost 140 cases were decided, rate case activity moderated somewhat in 2019, with about 125 electric and gas cases resolved. Through Sept. 30, 2020, excluding cases that were withdrawn, there were 82 cases decided. Currently, there are about 90 rate cases pending; however, since the onset of COVID-19, some utilities have postponed rate case filings that were planned for this year. This backlog, coupled with the need to address COVID-19 pandemic-related costs and lost revenue, may usher in an even more robust level of rate case activity in 2021 and beyond.

Absent the pandemic, increased costs associated with environmental compliance, generation and delivery infrastructure upgrades and expansion, renewable generation mandates, storm and disaster recovery, cybersecurity and employee benefits have contributed to an active rate case agenda over the last decade.

Rising interest rates over the past several years also likely contributed to the increased rate case activity. After holding rates near zero for several years, the Federal Reserve began raising the federal funds rate in 2015. Before the pandemic hit, the Fed, after more than a decade without a cut, lowered rates three times in 2019, due to signs of a slowing economy. Earlier this year, amid the economic fallout from the coronavirus outbreak, the Fed delivered two rate cuts, the first in early March, which cut rates by 50 basis points to 1.00% from 1.25%, and a second mid-March, which slashed rates another 100 basis points to the current range of 0%-0.25%. To facilitate economic recovery, Fed policymakers have indicated that rates will remain near zero through 2023.

Federal funds target rate, upper limit %



Data compiled Oct. 15, 2020.
Source: Federal Reserve

While changes in the federal funds rate do not move in lockstep with longer-term treasuries and authorized ROEs do not move in lockstep with interest rates, the expectation is that as interest rates change, authorized ROEs would also change in a similar fashion. However, several factors impact the timing and magnitude of such a shift. Normal regulatory lag, i.e., the amount of time it takes for a utility to put together a rate case filing and tender it to the commission and then for the commission to process the case, would without any other influences delay a change in average authorized ROEs relative to interest rates.

It is also worth noting that while both interest rates and authorized ROEs have generally been declining since 1990, the gap between authorized ROEs and interest rates widened somewhat over this period, largely as a result of an often-unstated understanding by regulators that the drop in interest rates caused by Federal Reserve intervention was unusual.

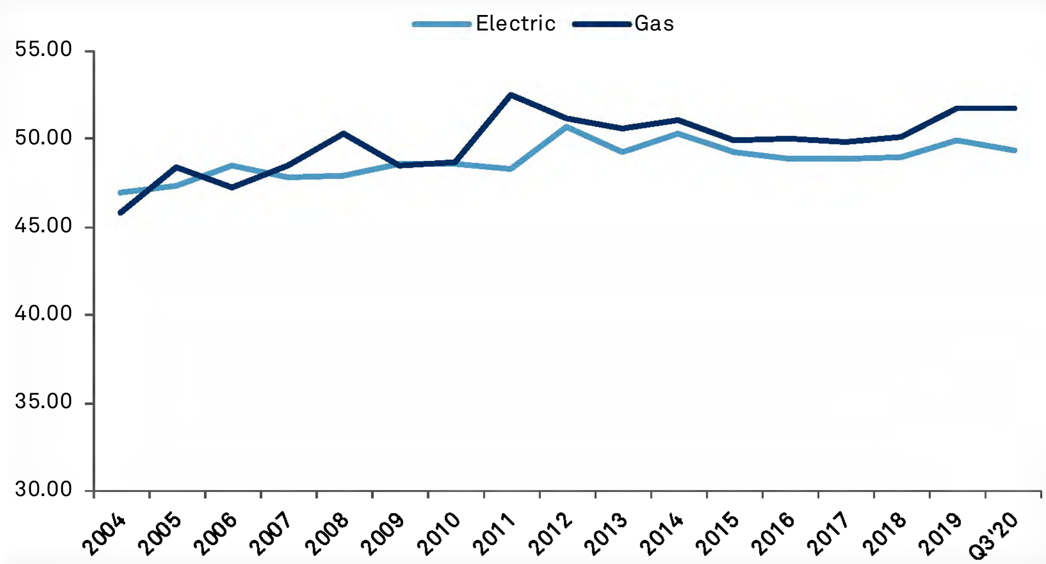
However, given the focus on customers' ability to pay and the need to maintain universal service as the pandemic drags on, regulators may be more apt to further lower authorized ROEs to mitigate the level of bill increases that result from recovery of pandemic-related costs. These considerations could be further complicated if a new administration seeks to roll-back the 2017 corporate tax reform initiatives.

Capital structure trends

To offset the negative cash flow impact of 2017 federal tax reform, many utilities sought higher common equity ratios, and the average authorized equity ratios adopted by utility commissions in 2019 were modestly higher than the levels observed in 2018 and 2017. In cases decided the first nine months of 2020, the average authorized equity ratio for electric utilities was 49.37%. For full-years 2019, 2018 and 2017, the average equity ratios authorized in electric utility cases were 49.94%, 49.02% and 48.90%, respectively. The average allowed equity ratio for gas utilities nationwide in cases decided in the first nine months of 2020 was 51.74%. For full-years 2019, 2018 and 2017, the average was 51.75%, 50.12% and 49.88%, respectively.

Taking a longer-term view, equity ratios have generally increased over the last several years — the average equity ratio approved in electric rate cases decided during 2004 was 46.96%, while the average for gas utilities was 45.81%. Many commissions began approving more equity-rich capital structures in the wake of the 2008 financial crisis.

Average authorized capital structures (%)



Data compiled Oct. 15, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

By contrast, RRA has observed that the actual financial equity ratios of the major utility holding companies in the team's Financial Focus coverage universe fell during the first six months of 2020. See the article Average utility equity ratio declines in 2020 amid COVID-19 pandemic.

A more granular look at ROE trends

The discussion thus far has looked broadly at trends in authorized ROEs; the sections that follow provide a more granular view based upon the types of proceedings/decisions in which these ROEs were established.

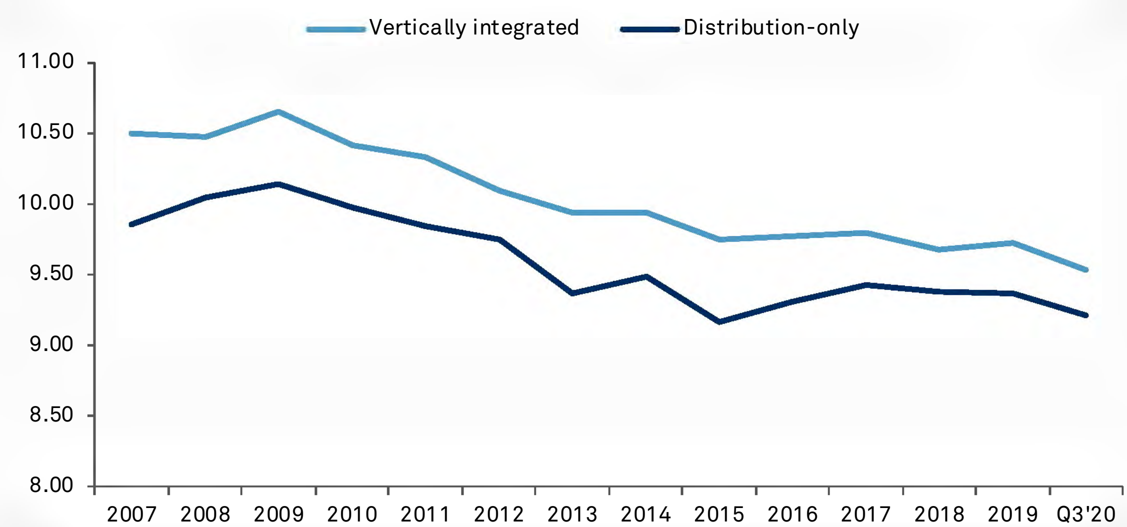
RRA has observed that there can be significant differences between the average ROEs from one subcategory of cases to another.

As a result of electric industry restructuring, certain states unbundled electric rates and implemented retail competition for generation. Commissions in those states now have jurisdiction only over the revenue requirement and return parameters for delivery operations.

Comparing electric vertically integrated cases versus delivery-only proceedings over the past several years, RRA finds that the annual average authorized ROEs in vertically integrated cases typically are about 30 to 65 basis points higher than in delivery-only cases, arguably reflecting the increased risk associated with ownership and operation of generation assets.

The industry average ROE for vertically integrated electric utilities was 9.54% in cases decided during the first nine months of 2020, versus the 9.73% average level posted in full-year 2019. For electric distribution-only utilities, the industry average ROE authorized in the first nine months of 2020 was 9.22%, versus 9.37% in full-year 2019. Included within the distribution returns for the first nine months of 2020 is the previously mentioned penalty ordered by the Maine PUC for Central Maine Power. Absent that 100 basis point penalty, the average ROE approved for distribution utilities in the first nine months of 2020 would have been 9.34%.

Average authorized electric ROEs (%)

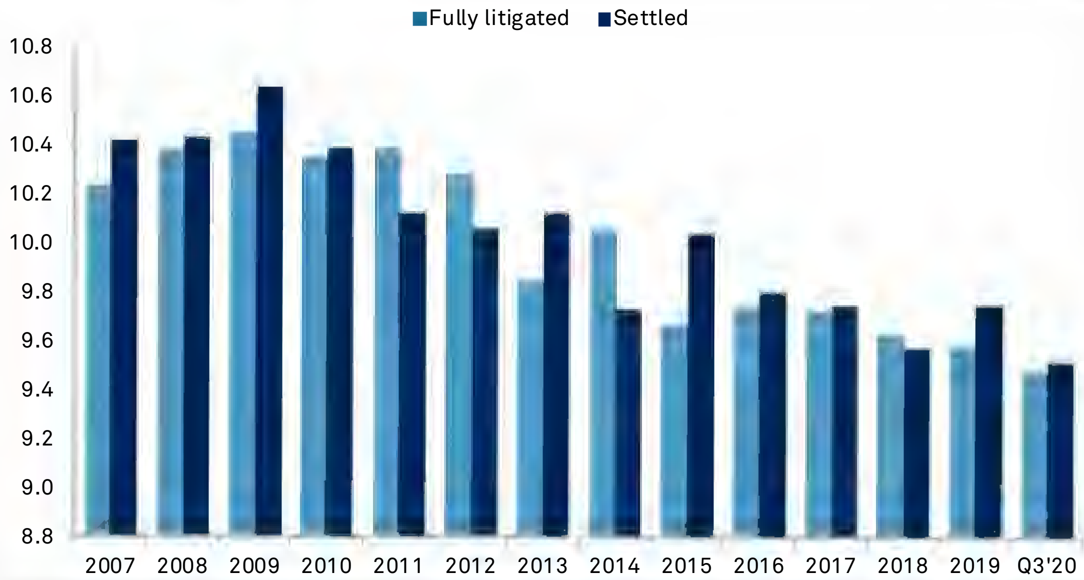


Data compiled Oct. 15, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Settlements have frequently been used to resolve rate cases over the last several years, and in many cases, these settlements are "black box" in nature and do not specify the ROE and other typical rate case parameters underlying the stipulated rate change. However, some states preclude this type of treatment, and settlements must specify these values, if not the specific adjustments from which these values were derived.

For both electric and gas cases, RRA has found no discernible pattern in the average authorized ROEs in cases that were settled versus those that were fully litigated. In some years, the average authorized ROE was higher for fully litigated cases, in others, it was higher for settled cases, and in a handful of years, the authorized ROE was similar for both fully litigated and settled cases.

Average authorized electric ROEs, settled vs. fully litigated cases (%)



Data compiled Oct. 15, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Average authorized gas ROEs, settled vs. fully litigated cases (%)

Data compiled Oct. 15, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

For several years, the annual average authorized ROEs in electric cases that involve limited-issue riders were meaningfully higher than those approved in general rate cases, driven primarily by the ROE premiums authorized in generation-related limited-issue rider proceedings in Virginia. However, these premiums were approved for limited durations and have since begun to expire. As a result, the gap between the average ROE observed in the rider cases and that observed in general rate cases has narrowed. Limited-issue rider cases in which a separate ROE is determined have had limited use in the gas industry, as most of the gas riders rely on ROEs approved in a previous base rate case.

The following discussion focuses on the corresponding tables available here.

Table 1 shows the average ROE authorized in major electric and gas rate decisions annually since 1990 and by quarter since 2016, followed by the number of observations in each period. Table 2 indicates the composite electric and gas industry data for all major cases, summarized annually since 2004 and by quarter for the past seven quarters.

Tables 3 and 4 provide comparisons since 2007 of average authorized ROEs for settled versus fully litigated cases, general rate cases versus limited-issue rider proceedings and vertically integrated cases versus delivery-only cases for electric and gas utilities, respectively.

The individual electric and gas cases decided in 2020 are listed in Table 5, with the decision date shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return, the ROE and the percentage of common equity in the adopted capital structure. Next, RRA indicates the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered at the time decisions were rendered. Fuel adjustment clause rate changes are not reflected in this study.

The simple mean is utilized for the return averages. In addition, the average equity returns indicated in this report reflect the ROEs approved in cases that were decided during the specified time periods and are not necessarily representative of either the average currently authorized ROEs for utilities industrywide or the returns actually earned by the utilities.

Please note: In an effort to align data presented in this report with data available in S&P Global Market Intelligence's online database, earlier historical data provided in previous reports may not match historical data in this report due to certain differences in presentation, including the treatment of cases that were withdrawn or dismissed.

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Table 1: ROEs authorized January 1990-September 2020

		Electric utilities			Gas utilities		
Year	**Period**	**Average ROE (%)**	**Median ROE (%)**	**Number of observations**	**Average ROE (%)**	**Median ROE (%)**	**Number of observations**
1990	Full year	12.70	12.77	38	12.68	12.75	33
1991	Full year	12.54	12.50	42	12.45	12.50	31
1992	Full year	12.09	12.00	45	12.02	12.00	28
1993	Full year	11.46	11.50	28	11.37	11.50	40
1994	Full year	11.21	11.13	28	11.24	11.27	24
1995	Full year	11.58	11.45	28	11.44	11.30	13
1996	Full year	11.40	11.25	18	11.12	11.25	17
1997	Full year	11.33	11.58	10	11.30	11.25	12
1998	Full year	11.77	12.00	10	11.51	11.40	10
1999	Full year	10.72	10.75	6	10.74	10.65	6
2000	Full year	11.58	11.50	9	11.34	11.16	13
2001	Full year	11.07	11.00	15	10.96	11.00	5
2002	Full year	11.21	11.28	14	11.17	11.00	19
2003	Full year	10.96	10.75	20	10.99	11.00	25
2004	Full year	10.81	10.70	21	10.63	10.50	22
2005	Full year	10.51	10.35	24	10.41	10.40	26
2006	Full year	10.32	10.23	26	10.40	10.50	15
2007	Full year	10.30	10.20	38	10.22	10.20	35
2008	Full year	10.41	10.30	37	10.39	10.45	32
2009	Full year	10.52	10.50	40	10.22	10.26	30
2010	Full year	10.37	10.30	61	10.15	10.10	39
2011	Full year	10.29	10.17	42	9.92	10.03	16
2012	Full year	10.17	10.08	58	9.94	10.00	35
2013	Full year	10.03	9.95	49	9.68	9.72	21
2014	Full year	9.91	9.78	38	9.78	9.78	26
2015	Full year	9.84	9.60	31	9.60	9.68	16
	1st quarter	10.29	10.50	9	9.48	9.50	6
	2nd quarter	9.60	9.60	7	9.42	9.52	6
	3rd quarter	9.76	9.80	8	9.47	9.50	4
	4th quarter	9.57	9.58	18	9.68	9.73	10
2016	**Full year**	**9.77**	**9.75**	**42**	**9.54**	**9.50**	**26**
	1st quarter	9.87	9.60	15	9.60	9.25	3
	2nd quarter	9.63	9.50	14	9.47	9.60	7
	3rd quarter	9.66	9.60	5	10.14	9.90	6
	4th quarter	9.74	9.60	19	9.68	9.55	8
2017	**Full year**	**9.74**	**9.60**	**53**	**9.72**	**9.60**	**24**
	1st quarter	9.75	9.90	13	9.68	9.80	6
	2nd quarter	9.54	9.50	13	9.43	9.50	7
	3rd quarter	9.67	9.70	11	9.69	9.60	13
	4th quarter	9.42	9.50	11	9.53	9.60	14
2018	**Full year**	**9.60**	**9.58**	**48**	**9.59**	**9.60**	**40**
	1st quarter	9.73	9.70	12	9.55	9.70	4
	2nd quarter	9.58	9.50	12	9.73	9.73	3
	3rd quarter	9.55	9.60	7	9.80	9.90	3
	4th quarter	9.70	9.68	16	9.73	9.70	22
2019	**Full year**	**9.65**	**9.60**	**47**	**9.71**	**9.70**	**32**
	1st quarter	9.58	9.50	19	9.35	9.40	9
	2nd quarter	9.55	9.45	9	9.55	9.65	3
	3rd quarter	**9.30**	**9.33**	**10**	**9.52**	**9.45**	**8**
2020	Year-to-date	9.50	9.44	38	9.45	9.42	20

Data compiled Oct. 15, 2020.

Year-to-date through Sept. 30, 2020.

Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

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Table 2: Electric and gas utilities summary

Electric utilities

Year	Period	ROR (%)	Number of observations	ROE (%)	Number of observations	Common equity to total capital (%)	Number of observations	Rate change amount ($M)	Number of observations
2004	Full year	8.71	20	10.81	21	46.96	19	1,806.3	29
2005	Full year	8.44	23	10.51	24	47.34	23	936.1	31
2006	Full year	8.32	26	10.32	26	48.54	25	1,318.1	39
2007	Full year	8.18	37	10.30	38	47.88	36	1,405.7	43
2008	Full year	8.21	39	10.41	37	47.94	36	2,823.2	44
2009	Full year	8.24	40	10.52	40	48.57	39	4,191.7	58
2010	Full year	8.01	62	10.37	61	48.63	57	4,921.9	78
2011	Full year	8.00	43	10.29	42	48.26	42	2,595.1	56
2012	Full year	7.95	51	10.17	58	50.69	52	3,080.7	69
2013	Full year	7.66	45	10.03	49	49.25	43	3,328.6	61
2014	Full year	7.60	32	9.91	38	50.28	35	2,053.7	51
2015	Full year	7.35	36	9.84	31	49.23	31	1,963.2	53
2016	Full year	7.28	41	9.77	42	48.91	41	2,326.1	58
2017	Full year	7.18	48	9.74	53	48.90	48	2,695.6	77
2018	Full year	6.90	49	9.60	48	49.02	49	1,880.4	67
	1st quarter	7.03	12	9.73	12	49.51	10	67.5	16
	2nd quarter	6.91	9	9.58	12	50.95	7	62.9	16
	3rd quarter	7.24	7	9.55	7	51.41	7	262.7	10
	4th quarter	6.85	16	9.70	16	49.12	16	1,268.1	20
2019	Full year	6.97	44	9.65	47	49.94	40	1,661.2	62
	1st quarter	6.82	20	9.58	19	48.72	21	700.9	22
	2nd quarter	6.82	8	9.55	9	48.64	8	452.3	12
	3rd quarter	7.03	10	9.30	10	51.33	10	188.5	12
2020	Year-to-date	6.88	38	9.50	38	49.37	39	1,341.7	46

Gas utilities

Year	Period	ROR (%)	Number of observations	ROE (%)	Number of observations	Common equity to total capital (%)	Number of observations	Rate change amount ($M)	Number of observations
2004	Full year	8.51	23	10.63	22	45.81	22	306.0	33
2005	Full year	8.24	29	10.41	26	48.40	24	465.4	35
2006	Full year	8.44	17	10.40	15	47.24	16	392.5	23
2007	Full year	8.11	31	10.22	35	48.47	28	645.3	43
2008	Full year	8.49	33	10.39	32	50.35	32	700.0	40
2009	Full year	8.15	29	10.22	30	48.49	29	438.6	36
2010	Full year	7.99	40	10.15	39	48.70	40	776.5	50
2011	Full year	8.09	18	9.92	16	52.49	14	367.0	31
2012	Full year	7.98	30	9.94	35	51.13	32	264.0	41
2013	Full year	7.43	21	9.68	21	50.60	20	498.7	40
2014	Full year	7.65	27	9.78	26	51.11	28	544.2	48
2015	Full year	7.34	16	9.60	16	49.93	16	494.1	40
2016	Full year	7.08	28	9.54	26	50.06	26	1,263.8	59
2017	Full year	7.26	24	9.72	24	49.88	24	410.7	54
2018	Full year	7.00	45	9.59	40	50.12	44	939.1	66
	1st quarter	7.37	4	9.55	4	51.40	4	90.4	9
	2nd quarter	7.75	3	9.73	3	58.87	3	48.3	10
	3rd quarter	6.52	5	9.80	3	43.86	4	619.5	16
	4th quarter	7.22	22	9.73	22	52.33	20	697.2	28
2019	Full year	7.18	34	9.71	32	51.75	31	1,455.3	63
	1st quarter	7.22	9	9.35	9	52.25	9	124.4	11
	2nd quarter	7.28	3	9.55	3	55.74	3	22.0	8
	3rd quarter	6.80	9	9.52	8	49.67	8	384.6	17
2020	Year-to-date	7.05	21	9.45	20	51.74	20	531.1	36

Data compiled Oct. 15, 2020.
Year-to-date through Sept. 30, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

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Table 3: Electric authorized ROEs: 2007-Q3'20

Settled versus fully litigated cases

	All cases			Settled cases			Fully litigated cases		
Year	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
2007	10.30	10.20	38	10.42	10.33	14	10.23	10.15	24
2008	10.41	10.30	37	10.43	10.25	17	10.39	10.54	20
2009	10.52	10.50	40	10.64	10.62	16	10.45	10.50	24
2010	10.37	10.30	61	10.39	10.30	34	10.35	10.10	27
2011	10.29	10.17	42	10.12	10.07	16	10.39	10.25	26
2012	10.17	10.08	58	10.06	10.00	29	10.28	10.25	29
2013	10.03	9.95	49	10.12	9.98	32	9.85	9.75	17
2014	9.91	9.78	38	9.73	9.75	17	10.05	9.83	21
2015	9.84	9.60	31	10.04	9.60	15	9.66	9.62	16
2016	9.77	9.75	42	9.80	9.85	17	9.74	9.60	25
2017	9.74	9.60	53	9.75	9.60	29	9.73	9.56	24
2018	9.60	9.58	48	9.57	9.63	26	9.63	9.53	22
2019	9.65	9.60	47	9.75	9.73	20	9.58	9.50	27
2020 YTD	9.50	9.44	38	9.52	9.45	15	9.48	9.40	23

General rate cases versus limited-issue riders

	All cases			General rate cases			Limited-issue riders		
Year	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
2007	10.30	10.20	38	10.32	10.23	36	9.90	9.90	1
2008	10.41	10.30	37	10.37	10.30	35	11.11	11.11	2
2009	10.52	10.50	40	10.52	10.50	38	10.55	10.55	2
2010	10.37	10.30	61	10.29	10.26	58	11.87	12.30	3
2011	10.29	10.17	42	10.19	10.14	40	12.30	12.30	2
2012	10.17	10.08	58	10.02	10.00	51	11.57	11.40	6
2013	10.03	9.95	49	9.82	9.82	40	11.34	11.40	7
2014	9.91	9.78	38	9.76	9.75	32	10.96	11.00	5
2015	9.84	9.60	31	9.60	9.53	23	10.87	11.00	6
2016	9.77	9.75	42	9.60	9.60	32	10.31	10.55	10
2017	9.74	9.60	53	9.68	9.60	42	10.01	9.95	10
2018	9.60	9.58	48	9.56	9.58	38	9.74	9.70	10
2019	9.65	9.60	47	9.64	9.65	33	9.68	9.31	14
2020 YTD	9.50	9.44	38	9.44	9.45	25	9.62	9.20	13

Vertically integrated cases vs. distribution-only cases

	All cases			Vertically integrated cases			Distribution-only cases		
Year	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
2007	10.30	10.20	38	10.50	10.45	26	9.86	9.98	10
2008	10.41	10.30	37	10.48	10.47	26	10.04	10.25	9
2009	10.52	10.50	40	10.66	10.66	28	10.15	10.30	10
2010	10.37	10.30	61	10.42	10.40	41	9.98	10.00	17
2011	10.29	10.17	42	10.33	10.20	28	9.85	10.00	12
2012	10.17	10.08	58	10.10	10.20	39	9.75	9.73	12
2013	10.03	9.95	49	9.95	10.00	31	9.37	9.36	9
2014	9.91	9.78	38	9.94	9.90	19	9.49	9.55	13
2015	9.84	9.60	31	9.75	9.70	17	9.17	9.07	6
2016	9.77	9.75	42	9.77	9.78	20	9.31	9.33	12
2017	9.74	9.60	53	9.80	9.65	28	9.43	9.55	14
2018	9.60	9.58	48	9.68	9.73	23	9.38	9.50	15
2019	9.65	9.60	47	9.73	9.73	25	9.37	9.60	8
2020 YTD	9.50	9.44	38	9.54	9.50	17	9.22	9.40	8

Data compiled Oct. 15, 2020.
Year-to-date through Sept. 30, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

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Table 4: Gas authorized ROEs: 2007-2020 Q3

Settled versus fully litigated cases

	All cases			Settled cases			Fully litigated cases		
Year	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
2007	10.22	10.20	35	10.24	10.18	22	10.20	10.40	13
2008	10.39	10.45	32	10.34	10.28	20	10.47	10.68	12
2009	10.22	10.26	30	10.43	10.40	13	10.05	10.15	17
2010	10.15	10.10	39	10.30	10.15	12	10.08	10.10	27
2011	9.92	10.03	16	10.08	10.08	8	9.76	9.80	8
2012	9.94	10.00	35	9.99	10.00	14	9.92	9.90	21
2013	9.68	9.72	21	9.80	9.80	9	9.59	9.60	12
2014	9.78	9.78	26	9.51	9.50	11	9.98	10.10	15
2015	9.60	9.68	16	9.60	9.60	11	9.58	9.80	5
2016	9.54	9.50	26	9.50	9.50	16	9.61	9.58	10
2017	9.72	9.60	24	9.68	9.60	17	9.82	9.50	7
2018	9.59	9.60	40	9.59	9.60	23	9.59	9.50	17
2019	9.71	9.70	32	9.70	9.70	20	9.74	9.72	12
2020 YTD	9.45	9.42	20	9.53	9.55	12	9.33	9.33	8

General rate cases versus limited-issue riders

	All cases			General rate cases			Limited-issue riders		
Year	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
2007	10.22	10.20	35	10.22	10.20	35	—	—	0
2008	10.39	10.45	32	10.39	10.45	32	—	—	0
2009	10.22	10.26	30	10.22	10.26	30	—	—	0
2010	10.15	10.10	39	10.15	10.10	39	—	—	0
2011	9.92	10.03	16	9.91	10.05	15	10.00	10.00	1
2012	9.94	10.00	35	9.93	10.00	34	10.40	10.40	1
2013	9.68	9.72	21	9.68	9.72	21	—	—	0
2014	9.78	9.78	26	9.78	9.78	26	—	—	0
2015	9.60	9.68	16	9.60	9.68	16	—	—	0
2016	9.54	9.50	26	9.53	9.50	25	9.70	9.70	1
2017	9.72	9.60	24	9.73	9.60	23	9.50	9.50	1
2018	9.59	9.60	40	9.59	9.60	39	9.50	9.50	1
2019	9.71	9.70	32	9.72	9.72	30	9.60	9.60	2
2020 YTD	9.45	9.42	20	9.45	9.42	20	—	—	0

Data compiled Oct. 15, 2020.
Year-to-date through Sept. 30, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

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Table 5: Electric and gas utility decisions

Electric utility decisions

Date	Company	State	ROR (%)	ROE (%)	Common equity as % of capital	Test year	Rate base	Rate change amount ($)	Footnotes
1/8/20	Interstate Power and Light Co.	IA	7.23	10.02	51.00	12/20	Average	127.0	B, I
1/16/20	Consolidated Edison Co. of New York, Inc.	NY	6.61	8.80	48.00	12/20	Average	113.3	B, D, Z
1/22/20	Rockland Electric Co.	NJ	7.11	9.50	48.32	9/19	Year-end	12.0	B, D
1/23/20	Indiana Michigan Power Co.	MI	6.08	9.86	46.56	12/20	Average	36.4	B,*
2/3/20	Virginia Electric and Power Co.	VA	6.84	9.20	51.17	3/21	Average	-6.3	LIR,1
2/3/20	Virginia Electric and Power Co.	VA	6.84	9.20	51.17	3/21	Average	11.4	LIR,2
2/3/20	Virginia Electric and Power Co.	VA	7.35	10.20	51.17	3/21	Average	-20.3	LIR,3
2/3/20	Virginia Electric and Power Co.	VA	7.35	10.20	51.17	3/21	Average	0.7	LIR,4
2/6/20	PacifiCorp	CA	—	10.00	51.96	12/19	Average	-5.8	
2/11/20	Public Service Co. of Colorado	CO	6.97	9.30	55.61	8/19	Average	292.7	5,6
2/14/20	CenterPoint Energy Houston Electric, LLC	TX	6.51	9.40	42.50	12/18	Year-end	55.9	B, D,Hy
2/18/20	Virginia Electric and Power Co.	VA	7.35	10.20	51.17	3/21	Average	-13.0	LIR,7
2/19/20	Central Maine Power Co.	ME	6.30	8.25	50.00	6/18	Average	17.4	D,Hy,8
2/24/20	Virginia Electric and Power Co.	NC	7.20	9.75	52.00	12/18	Year-end	5.0	B, I,Hy,9
2/25/20	Appalachian Power Co.	VA	7.74	10.42	50.78	4/21	Average	-6.3	LIR,10
2/27/20	AEP Texas Inc.	TX	6.45	9.40	42.50	12/18	Year-end	0.7	B, D,Hy
2/28/20	Oklahoma Gas and Electric Co.	AR	5.33	—	37.92	3/20	Year-end	5.2	B,11,*
3/11/20	Indiana Michigan Power Co.	IN	5.61	9.70	37.55	12/20	Year-end	77.1	Z,*
3/17/20	Mississippi Power Co.	MS	7.57	—	53.00	12/20	Year-end	-16.7	B
3/18/20	Union Electric Co.	MO	—	—	—	12/18	—	-32.0	B,12
3/20/20	Virginia Electric and Power Co.	VA	6.84	9.20	51.17	5/21	Average	18.0	LIR,13
3/25/20	Avista Corp.	WA	7.21	9.40	48.50	12/18	—	28.5	B
2020	**1st quarter: averages/total**		**6.82**	**9.58**	**48.72**			**700.9**	
	Observations		**20**	**19**	**21**			**22**	
4/6/20	Kentucky Utilities Co.	VA	—	—	—	12/18	—	9.0	B
4/7/20	Northern States Power Co. - MN	MN	—	—	—	—	—	—	14
4/13/20	Virginia Electric and Power Co.	VA	6.84	9.20	51.17	5/20	Average	7.4	LIR,15
4/17/20	Fitchburg Gas and Electric Light Co.	MA	7.99	9.70	52.45	12/18	Year-end	1.1	B, D
4/27/20	Duke Energy Kentucky, Inc.	KY	6.41	9.25	48.23	3/21	Average	24.1	
5/8/20	DTE Electric Co.	MI	5.46	9.90	38.32	4/21	Average	188.3	*
5/20/20	Southern Indiana Gas and Electric Co.	IN	—	—	—	10/19	Year-end	7.4	LIR,16
5/20/20	Southwestern Public Service Co.	NM	7.19	9.45	54.77	3/19	Year-end	31.0	B
5/21/20	Appalachian Power Co.	VA	—	9.42	—	6/21	Year-end	4.0	LIR,17
6/23/20	Virginia Electric and Power Co.	VA	7.35	10.20	51.17	8/21	Average	-20.1	B, LIR,18
6/26/20	Appalachian Power Co.	WV	—	—	—	12/19	—	50.1	B, LIR
6/29/20	Duke Energy Indiana, LLC	IN	5.71	9.70	40.98	12/20	Year-end	145.9	Z,*
6/30/20	Liberty Utilities (Granite State Electric) Corp.	NH	7.60	9.10	52.00	12/18	Year-end	4.2	B, D, Z, I
	2nd quarter: averages/total		**6.82**	**9.55**	**48.64**			**452.3**	
	Observations		**8**	**9**	**8**			**12**	
7/1/20	Empire District Electric Co.	MO	6.77	9.25	46.00	3/19	—	1.0	B
7/1/20	Virginia Electric and Power Co.	VA	6.84	9.20	51.17	8/21	Average	-5.2	LIR,19
7/8/20	Puget Sound Energy, Inc.	WA	7.39	9.40	48.50	12/18	Year-end	59.6	
7/14/20	Delmarva Power & Light Co.	MD	6.84	9.60	50.53	8/19	Average	11.7	D
7/28/20	Hawaii Electric Light Co., Inc.	HI	7.52	9.50	56.83	12/19	Average	0.0	B, I
7/30/20	Virginia Electric and Power Co.	VA	6.84	9.20	51.17	8/21	Average	10.6	LIR,20
8/27/20	Green Mountain Power Corp.	VT	6.43	8.20	49.87	9/21	Average	0.0	21
8/27/20	Liberty Utilities (CalPeco Electric) LLC	CA	7.63	10.00	52.50	12/19	Average	1.4	
8/27/20	Southwestern Public Service Co.	TX	7.13	9.45	54.62	6/19	Year-end	88.0	B, I
9/4/20	Virginia Electric and Power Co.	VA	6.88	9.20	52.07	10/20	Average	-19.4	LIR,22
9/23/20	Massachusetts Electric Co.	MA	—	—	—	—	—	46.1	D,23
9/24/20	Lone Star Transmission, LLC	TX	—	—	—	—	—	-5.3	B,24
	3rd quarter: averages/total		**7.03**	**9.30**	**51.33**			**188.5**	
	Observations		**10**	**10**	**10**			**12**	
2020	**YTD: averages/total**		**6.88**	**9.50**	**49.37**			**1,341.7**	
	Observations		**38**	**38**	**39**			**46**	

Date	Company	State	ROR (%)	ROE (%)	Common equity as % of capital	Test year	Rate base	Rate change amount ($)	Footnotes
Gas utility decisions									
1/15/20	MDU Resources Group Inc.	WY	7.08	9.35	51.25	12/18	Year-end	0.8	B
1/16/20	Consolidated Edison Co. of New York, Inc.	NY	6.61	8.80	48.00	12/20	Average	83.9	B,Z
1/24/20	Roanoke Gas Co.	VA	7.28	9.44	59.64	12/17	Average	7.3	I
1/29/20	Indiana Gas Co., Inc.	IN	—	—	—	6/19	Year-end	1.8	LIR,16
1/29/20	Southern Indiana Gas and Electric Co.	IN	—	—	—	6/19	Year-end	2.2	LIR,16
2/3/20	Cascade Natural Gas Corp.	WA	7.24	9.40	49.10	12/18	—	6.5	B
2/24/20	Atmos Energy Corp.	KS	7.03	9.10	56.32	3/19	Year-end	3.1	
2/25/20	Questar Gas Co.	UT	7.18	9.50	55.00	12/20	Average	2.7	Z
2/28/20	Fitchburg Gas and Electric Light Co.	MA	7.99	9.70	52.45	12/18	Year-end	4.6	B,Z
2/28/20	Liberty Utilities (EnergyNorth Natural Gas) Corp.	NH	—	—	—	—	—	—	14
3/25/20	Avista Corp.	WA	7.21	9.40	48.50	12/18	—	8.0	B
3/26/20	Northern Utilities, Inc.	ME	7.34	9.48	50.00	12/18	Year-end	3.6	Hy
2020	**1st quarter: averages/total**		**7.22**	**9.35**	**52.25**			**124.4**	
	Observations		**9**	**9**	**9**			**11**	
4/21/20	Atmos Energy Corp.	TX	7.71	9.80	60.12	—	—	-0.3	B
4/28/20	Delta Natural Gas Co., Inc.	KY	—	—	—	12/19	Year-end	3.4	LIR,25
5/13/20	Missouri Gas Energy	MO	—	—	—	2/20	—	5.6	B, LIR,26
5/13/20	Spire Missouri Inc.	MO	—	—	—	2/20	—	5.5	B, LIR,26
5/19/20	Black Hills Colorado Gas, Inc.	CO	6.76	9.20	50.15	6/18	Average	-2.3	
6/16/20	CenterPoint Energy Resources Corp.	TX	7.38	9.65	56.95	6/19	Year-end	4.0	B
6/23/20	Black Hills Kansas Gas Utility Co., LLC	KS	—	—	—	1/20	Year-end	1.6	LIR,27
6/24/20	Northern Indiana Public Service Co.	IN	—	—	—	12/19	Year-end	4.5	LIR,16
	2nd quarter: averages/total		**7.28**	**9.55**	**55.74**			**22.0**	
	Observations		**3**	**3**	**3**			**8**	

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Table 5: Electric and gas utility decisions

Electric utility decisions

Date	Company	State	ROR (%)	ROE (%)	Common equity as % of capital	Test year	Rate base	Rate change amount ($)	Footnotes
7/8/20	Oklahoma Natural Gas Co.	OK	—	—	—	12/19	—	9.7	B,23
7/8/20	Puget Sound Energy, Inc.	WA	7.39	9.40	48.50	12/18	Year-end	42.9	
7/14/20	CenterPoint Energy Resources Corp.	OK	—	—	—	12/19	—	-2.5	B,23
7/22/20	Indiana Gas Co., Inc.	IN	—	—	—	12/19	Year-end	2.8	LIR,16
7/22/20	Southern Indiana Gas and Electric Co.	IN	—	—	—	12/19	Year-end	0.7	LIR,16
8/4/20	Texas Gas Service Co., Inc.	TX	7.46	9.50	59.00	6/19	—	10.3	B
8/14/20	Summit Natural Gas of Missouri, Inc.	MO	—	—	—	—	—	—	14
8/20/20	DTE Gas Co.	MI	—	9.90	—	9/21	Average	110.0	B
8/21/20	Questar Gas Co.	WY	7.11	9.35	55.00	12/19	Year-end	1.5	B
8/27/20	Virginia Natural Gas, Inc.	VA	—	—	—	10/21	Average	3.0	LIR,28
9/10/20	Consumers Energy Co.	MI	—	9.90	—	9/21	Average	144.0	B
9/11/20	Roanoke Gas Co.	VA	7.30	—	—	9/21	Average	2.3	LIR,28
9/14/20	Chattanooga Gas Co.	TN	7.12	—	49.23	12/19	Average	4.8	B,29
9/23/20	South Jersey Gas Co.	NJ	6.90	9.60	54.00	6/20	Year-end	39.5	B
9/25/20	Southwest Gas Corp.	NV	6.75	9.25	49.26	—	—	0.6	
9/25/20	Southwest Gas Corp.	NV	6.52	9.25	49.26	—	—	22.7	
9/28/20	CenterPoint Energy Resources Corp.	AR	4.62	—	33.07	9/21	Year-end	-12.1	*,11
9/30/20	Atmos Energy Corp.	KY	—	—	—	9/21	Year-end	4.5	LIR,30
	3rd quarter: averages/total		**6.80**	**9.52**	**49.67**			**384.6**	
	Observations		**9**	**8**	**8**			**17**	
2020	**YTD: averages/total**		**7.05**	**9.45**	**51.74**			**531.1**	
	Observations		**21**	**20**	**20**			**36**	

Data compiled Oct. 15, 2020.
Year-to-date through Sept. 30, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Footnotes

A- *Average.*
B- *Order followed stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.*
D- *Applies to electric delivery only.*
Hy *Hypothetical capital structure adopted.*

I- *Interim rates implemented prior to the issuance of final order, normally under bond and subject to refund.*
LIR *Limited-issue rider proceeding.*
NA *Not available at the time of publication.*
Z- *Rate change implemented in multiple steps.*

* *Capital structure includes cost-free items or tax credit balances at the overall rate of return.*
1 *Rate change was approved under Rider B, which is the mechanism through which the company recovers the costs associated with the conversion of the Altavista, Hopewell and Southampton power s*
2 *Rate change was approved under Rider GV, which is the mechanism through which the company recovers its investment in the Greensville County generation facility.*

3 *Rate change was approved under Rider S, which is the mechanism through which the company recovers its investment in the Virginia City Hybrid Energy Center.*
4 *Rate change was approved under Rider W, which is the mechanism through which the company recovers its investment in the Warren County generation facility.*
5 *While the specified 2/11/20 date coincides with the date of the PUC's written order, the authorized base rate change coincides with a compliance filing submitted by the company on 2/18/20 and imple*
6 *The company petitioned the PUC for a rehearing on 3/2/20. On 7/14/20, the PUC issued an order granting in part and denying in part reconsideration motions filed by the company, as well as other intervenors in the proceeding.*
7 *Rate change was approved under Rider R, which is the mechanism through which the company recovers its investment in the Bear Garden power plant.*
8 *Decision reflects date of written order issued on Feb. 19, 2020. The ROE authorized reflects a 100 basis point downward adjustment for poor service. The PUC ordered that this ROE disallowance be lifted when the utility meets all performance benchmarks for all service equality metrics for at least 18 consecutive months beginning March 1, 2020, and formally demonstrates to the commission that problems have been solved.*
9 *Company seeks reconsideration regarding coal ash cost recovery.*
10 *This case addresses the company's investment in the Dresden Generating Plant.*

11 *Rate change pursuant to company's formula rate plan.*
12 *The approved partial settlements were largely silent regarding traditional rate case parameters, including capital structure and rate base, but notes that the stipulated return on equity is in a range of 9.*
13 *Reflects recovery of two utility-scale solar generation facilities, the 142-MW Colonial Trail West Solar Facility and the 98-MW AC Spring Grove 1 Solar Facility.*
14 *Case withdrawn or closed.*
15 Rate change approved under US-4, which is the mechanism through which the company will recover its investment in the roughly 100 megawatt utility-scale solar generation facility, Sadler Solar Facil
16 Case established the rates to be charged to customers under the company's compliance and system improvement adjustment mechanism, which includes both federally mandated pipeline-safety initiatives and projects that are permitted under the state's "transmission, distribution, and storage system improvement charge" statute.
17 Rate change authorized under company's energy efficiency rider.
18 Rate change approved under Rider BW, which is the mechanism through which the company recovers its investment in the 1358 MW natural gas-fired combined-cycle Brunswick County Power Statio
19 Rate change approved under Rider US-2, which is the mechanism through which the company recovers its investment in three utility-scale solar facilities: Scott Solar; Whitehouse Solar; and, Woodla
20 Rate change under Rider DSM, which is a consolidation of three riders that reflect costs associated with the company's demand-side management and energy conservation program.
21 Reflects authorization under company's multi-year alternative regulation plan.
22 Rate change approved under Rider E, which allows for recovery of costs incurred to comply with the U.S. Environmental Protection Agency and Virginia Waste Management Board regulations related
23 Rate change under performance-based regulation plan.
24 Transmission rate case.
25 Rate change authorized under the company's pipe replacement program rider.
26 Rate change authorized under the company's infrastructure system replacement surcharge rider.
27 Case involves company's gas system reliability surcharge.
28 Rate change was approved under company's rider pertaining to investment made under Virginia Steps to Advance Virginia Energy infrastructure program.
29 Rate change under company's annual rate mechanism.
30 Rate change approved under company's pipeline replacement program rider.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 70

Responding Witness: Adrien M. McKenzie

Q-70. Refer to the McKenzie Testimony, page 45 lines 7–11 and Exhibit No. 4. As quoted in the FERC Opinion, if the purpose of the outlier test is "to exclude from the proxy group those companies whose Return On Equity (ROE) estimated are below the average bond yield or above the average bond yield, but are sufficiently low that an investor would consider the stock to yield essentially the same return as debt," explain why it would be either appropriate to:

a. Exclude those companies from the proxy group whose ROEs were excluded from the DCF analysis; or

b. Include all the observations, excluding none, since there are at least two additional ROE estimates derived from other sources.

A-70.

a. In applying tests of low-end values, FERC eliminates results for those companies in the proxy group that fall outside the established threshold. Thus, the cost of equity estimate for that company is not considered in evaluating the overall result for the proxy group. FERC performs this test based on the results of each method independently, so that a proxy firm that is excluded from consideration because its DCF estimate falls below the low-end threshold would still be included in evaluating the CAPM results, so long as its CAPM cost of equity estimate exceeded the threshold. This methodology appropriately excludes only those values which are determined to fall below the threshold test of reasonableness, while retaining all estimates that exceed the test.

b. See the response to part a.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 71

Responding Witness: Adrien M. McKenzie

Q-71. Refer to the McKenzie Testimony, Exhibit No. 4.

a. Explain why PPL Corporation is not listed in the Proxy Group.

b. Explain whether any of the companies in the Proxy Group have had a credit downgrade or put on notice of the potential of a downgrade as a result of carbon transition risk.

c. Explain whether any of the companies listed in the Proxy Group assign a high, moderate, or low probability of carbon regulation in their long-range resource plans.

A-71.

a. PPL Corporation was excluded from the proxy group due to its planned sale of its utility operations in the United Kingdom.

b. Mr. McKenzie has not conducted any research studies to determine whether the utilities included in his proxy group have been downgraded over some past period or for what reasons; nor was such a study necessary to support the conclusions and recommendations contained in his testimony.

c. Mr. McKenzie has not reviewed the long-range resource plans for the utilities included in his proxy group; nor was this necessary to support the conclusions and recommendations contained in his testimony.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 72

Responding Witness: Adrien M. McKenzie

Q-72. Refer to the McKenzie Testimony, Exhibit No. 4. Many of the companies in the Proxy Group have extensive unregulated and or foreign operations while LG&E and KU do not.

a. Explain why these outside influences on the parent holding companies' financial operations should not be minimized within if not eliminated from the Proxy Group.

b. For each company in the Proxy Group, provide the percent of revenue derived from U.S. electric and gas (not storage or interstate transportation) operations regulated

A-72.

a. Mr. McKenzie's direct testimony at pages 24-32 contains an extensive discussion of the relative risk pertaining to his proxy group of utilities. As Mr. McKenzie explains, his identification of a proxy group of risk-comparable utilities focuses primarily on credit ratings, which provide an objective indicator of investment risk that considers the key risk factors relevant to investors, including quantitative and qualitative factors. As the Managing Director for Moody's Global Regulatory Affairs noted in comments to the Securities and Exchange Commission:

> To meet market needs over time, credit ratings have developed important attributes including insightful, robust and independent analysis, symbols that succinctly communicate opinions, and broad coverage across markets, industries and asset classes. These attributes have enabled credit ratings to serve as a point of reference and common language of credit that is used by financial market professionals worldwide to compare

> credit risk across jurisdictions, industries and asset classes, thereby facilitating the efficient flow of capital worldwide.[14]

A comparison of credit ratings is widely accepted as a means of evaluating the relative risks of utilities for purposes of identifying a proxy group in the context of estimating the cost of equity. For example, the Federal Energy Regulatory Commission has concluded that "corporate credit ratings are a reasonable measure to use to screen for investment risk," and that "[c]redit ratings are a key consideration in developing a proxy group that is risk comparable."[15] FERC has also ruled that the measure of comparable risks afforded a credit rating screen alone is a sufficient test of comparable investment risks.[16]

In addition to credit ratings, Mr. McKenzie also examines a number of key metrics (i.e., beta, Value Line Safety Rank, Value Line Financial Strength Rating) that are widely recognized as independent guides to the investment risks associated with common stocks. Moreover, these measures incorporate the impact of a broad spectrum of risks, including business and financial position, relative size, and exposure to company-specific factors. As Mr. McKenzie indicated at page 42 of his direct testimony, these objective measures indicate that the overall investment risks for LGE/KU are generally comparable to those of the firms in his proxy group. In other words, "extensive unregulated and or foreign operations" do not differentiate the risks of the proxy group from those of LGE/KU.

The Supreme Court has recognized that the degree of risk, not the nature of the business, is relevant in evaluating an allowed ROE for a utility.[17] The cost of capital is based on the returns that investors could realize by putting their money in other alternatives, and the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment. The simple observation that a firm operates in non-utility businesses says nothing at all about the overall investment risks perceived by investors, which is the very basis for a fair rate of return. Similarly, gas distribution operations are regulated by the states in the same manner as electric operations, and there is no basis to distinguish between revenues from electric and gas utility

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[14] Farisa Zarin, Letter Re: Credit Rating Standardization Study – Release No. 34-63573; File No. 4-622 (Feb. 18, 2011). Available at: https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=5&cad=rja&uact=8&ved=0ahUKEwjM7uicuMrbAhUGRqwKHeY0BGkQFghJMAQ&url=https%3A%2F%2Fwww.sec.gov%2Fcomments%2F4-622%2F4622-15.pdf&usg=AOvVaw3Lsgo0DWInU17QdvxEuw9v (last visited Jan. 16, 2021).
[15] Potomac-Appalachian Transmission Highline, L.L.C., 133 FERC ¶ 61,152, at P 63 (2010).
[16] N. Pass Transmission LLC, 134 FERC ¶ 61,095 at P 52 & n.70 (2011).
[17] *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923) ("A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time . . . on investments in other business undertakings which are attended by corresponding risks and uncertainties . . .").

operations. Regulatory standards governing a fair ROE are based on comparable risk, not the nature of the business.

In fact, as Mr. McKenzie's testimony explains at pages 72-76, returns in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. Under the regulatory standards established by Hope and Bluefield, the salient criterion in establishing a meaningful proxy group to estimate investors' required return is relative risk, not the source of the revenue stream or the nature of the asset base. Moreover, due to differences in business segment definition and reporting between utilities, it is often impossible to accurately apportion financial measures, such as revenues and total assets, between regulated (e.g., electric and gas) and non-regulated sources. As a result, even if one were to ignore the fact that there is no clear link between the nature of a utility's revenues or assets and investors' risk perceptions, it is generally not possible to accurately and consistently apply asset or revenue-based criteria. In fact, FERC has specifically rejected arguments that utilities "should be excluded from the proxy group given the risk factors associated with its unregulated, non-utility business operations."[18]

b. Mr. McKenzie did not calculate the requested statistic in the course of preparing his testimony; nor was it necessary to support his analyses and conclusions. To the extent the information necessary to perform these calculation is publicly available, it can be obtained from the Form 10-K reports for each of the proxy companies, which can be obtained at https://www.sec.gov/edgar/searchedgar/legacy/companysearch.html.

[18] Bangor Hydro-Elec. Co., 117 FERC ¶ 61,129 at PP 19, 26 (2006).

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 73

Responding Witness: Adrien M. McKenzie

Q-73. Refer to the McKenzie Testimony, Table 2, page 46. Provide an update to the table using the most current available from IHS Global Insight and the Energy Information Administration and the current Baa - Aa yield spread. Include in the response the monthly observations for the Baa and Aa yields.

A-73. Mr. McKenzie does not have a more recent forecast from IHS Global Insight. The Energy Information Administration publishes an annual forecast, with the next long-term forecast being scheduled for release on February 3, 2021 and publicly available at https://www.eia.gov/outlooks/aeo/.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 74

Responding Witness: Adrien M. McKenzie

Q-74. Refer to the McKenzie Testimony, page 50, lines 8–13.

a. Explain why the individual firm's dividend yield and growth rate are weighted by its proportionate share of total market value.

b. Explain why a similar procedure would not be appropriate for the DCF analysis in Exhibit No. 4.

A-74.

a. The S&P 500, which is a widely cited proxy for the market as a whole, is a market-weighted stock index. Thus, to estimate the market rate of return based on the dividend-paying firms in the S&P 500, it is necessary to weight the individual firm's dividend yield and growth rate by its proportionate share of total market value.

b. Application of the DCF model and other methodologies (e.g., CAPM) to firms in the electric utility industry does not involve the use of a market value weighted stock index as a proxy. Rather, financial models such as the DCF are applied directly to a group of firms that have been determined to be risk comparable. As a result, once illogical values have been eliminated, each observation represents a valid estimate of investors' required rate of return and there is no basis to give greater weight to any single result.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 75

Responding Witness: Adrien M. McKenzie

Q-75. Refer to the McKenzie Testimony, page 51, lines 2–20, through page 52, lines 1–4. Provide a list of state regulatory commissions that Mr. McKenzie has appeared before that have rejected and accepted his size adjustment in the last five years.

A-75. Mr. McKenzie did not conduct any research studies of regulatory orders in other state jurisdictions regarding treatment of the size adjustment in past proceedings to support the size adjustment used in his application of the CAPM and ECAPM methods; rather, it was predicated on the results of financial research indicating that beta does not fully account for the impact of firm size on investors' required returns. Moreover, in Mr. McKenzie's experience, regulatory agencies generally do not rule on specific details underlying the results of financial models or even indicate precisely which results were relied on specifically in arriving at their authorized ROE.

The size adjustment methodology used by Mr. McKenzie is identical to that approved by the Federal Regulatory Commission, which has concluded that "[t]his type of size adjustment is a generally accepted approach to CAPM analyses."[19] Similarly, a recent publication available from the National Association of Certified Valuators and Analysts documented the relevance of the size adjustment in applying the CAPM:

> [A] beta-adjusted size premium is also an indication of the relative market performance of small-cap versus large-cap stocks, but is typically used for a very specific purpose: as a "size" adjustment within the context of the capital asset pricing model (CAPM) when developing cost of equity capital estimates. A size adjustment is typically applied to the CAPM to make up for the fact that the betas of smaller companies do not fully explain their observed returns. Because the CAPM already includes a beta input in its textbook specification, the size premium is then "beta adjusted" to remove the portion of

[19] Coakley v. Bangor Hydro-Elec. Co., Opinion No. 531-B, 150 FERC ¶ 61,165 P 117 (2015).

> realized excess return that is attributable to beta, thereby isolating the size effect's contribution to realized excess return and avoiding double counting the impact of each factor.
>
> Another way of saying this is that within the context of the CAPM, the betas of small-cap companies do not fully account for (or explain) their actual returns. Because the amount of this difference (what actually happened versus what CAPM predicted) varies with "size" (in this case, as measured by market capitalization) we call it a "size premium".[20]

This article went on to conclude that "valuation professionals typically add a 'size premium' to the base CAPM equation. . ." A copy of the article is attached.

[20] National Association of Certified Valuators and Analysts, "Using a Non-Beta-Adjusted Size Premium in the Context of the CAPM Will Likely Overstate Risk and Understate Value" (Jan. 30, 2019).

Using a Non-Beta-Adjusted Size Premium in the Context of the CAPM Will Likely Overstate Risk and Understate Value

QR quickreadbuzz.com/2019/01/30/business-valuation-grabowski-harringtonsing-a-non-beta-adjusted-size-

National Association of Certified Valuators and Analysts January 31, 2019

Measuring the Relative Performance of Small Stock vs. Large Stock and the Cost of Equity

Roger Ibbotson and James Harrington discuss two different ways of measuring the relative performance of small stocks versus large stocks in this article: (i) the "small stock premium" and (ii) the "beta-adjusted size premium". Ibbotson and Harrington demonstrate why using a non-beta-adjusted size premium within the context of the capital asset pricing model (CAPM) to estimate cost of equity capital will likely "double count" beta risk, and therefore overstate risk and understate value. The authors also demonstrate that a non-beta-adjusted size premium used in conjunction with "build-up" methods that employ an industry risk premium would be equally inappropriate.

Roger Ibbotson and James Harrington discuss two different ways of measuring the relative performance of small stocks versus large stocks in this article: (i) the "small stock premium" and (ii) the "beta-adjusted size premium". Ibbotson and Harrington demonstrate why using a non-beta-adjusted size premium within the context of the capital asset pricing model (CAPM) to estimate cost of equity capital will likely "double count" beta risk, and therefore

overstate risk and understate value. The authors also demonstrate that a non-beta-adjusted size premium used in conjunction with "build-up" methods that employ an industry risk premium would be equally inappropriate.[1],[2]

The "Small Stock Premium" and the "Beta-Adjusted Size Premium" Are Different Things, and are Used for Different Purposes

The "small stock premium" and a "beta-adjusted size premium" are both informative about the performance of small company stocks relative to large company stocks. However, they are different things, and are used for different purposes.

The small stock premium is the difference between the returns of small capitalization (small-cap) stocks and large capitalization (large-cap) stocks. This difference can be used in a top-down review of market performance and general discussions of whether small-cap stocks perform better than large-cap stocks over time and can also be used to develop long-term inputs for use in mean-variance optimization (MVO) analyses or wealth forecasting.[3]

Alternatively, a beta-adjusted size premium is also an indication of the relative market performance of small-cap versus large-cap stocks, but is typically used for a very specific purpose: as a "size" adjustment within the context of the capital asset pricing model (CAPM) when developing cost of equity capital estimates.[4] A size adjustment is typically applied to the CAPM to make up for the fact that the betas of smaller companies do not fully explain their observed returns. Because the CAPM already includes a beta input in its textbook specification, the size premium is then "beta adjusted" to remove the portion of realized excess return that is attributable to beta, thereby isolating the size effect's contribution to realized excess return and avoiding double counting the impact of each factor.

Calculating the Small Stock Premium

The "small stock premium" can be defined as the simple difference between small-cap stock total returns (as measured by the Ibbotson Associates Small Company Stock total return index) and large-cap stock total returns (as measured by the Ibbotson Associates Large Company Stock total return index).[5],[6] The small-stock premium is given by:[7],[8]

Small Stock Premium = (Small Stock Total Return – Large Stock Total Return)

In Exhibit 1, the small stock premium is calculated on an annual basis from 2010 through 2017.

Exhibit 1: Annual Small Stock Premium (2010–2017)

	Large Stock Total Return	Small Stock Total Return	Small Stock Premium
2010	15.06%	31.26%	16.20%
2011	2.11%	-3.26%	-5.37%
2012	16.00%	18.24%	2.23%
2013	32.39%	45.07%	12.68%
2014	13.69%	2.92%	-10.77%
2015	1.38%	-3.60%	-4.98%
2016	11.96%	25.65%	13.69%
2017	21.83%	11.19%	-10.64%

Source of underlying data in Exhibit 1: Stocks, Bonds, Bills, and Inflation® (SBBI®) return series from the Morningstar *Direct* database. Series used: (i) Large Company Stocks (IA SBBI® US Large Stock TR USD Ext). The "SBBI ® US Large Stock" return series is essentially the S&P 500 index. (ii) Small Company Stocks (IA SBBI® US Small Stock TR USD). Used with permission. All rights reserved. Calculations performed by Duff & Phelps, LLC.

For example, in calendar year 2010, small-cap stocks had a total return of 31.26%, and large-cap stocks (as measured by the S&P 500 total return index) had a total return of 15.06%. The small stock premium for 2010 was therefore 31.26% – 15.06%, or 16.20%. Note that the small stock premium is not always positive, especially over shorter periods of time.[9]

The small stock premium can also be calculated over longer periods of time. For example, the average annual return of large-cap stocks (as measured by the S&P 500 total return index) from 1926 through 2017 was 12.06%, and the average annual return of small-cap stocks (as measured by the Ibbotson Associates Small Company Stock total return index) over the same period was 16.52%, implying a small stock premium of 4.46% (16.52% – 12.06%).[10]

Calculating a Beta-Adjusted Size Premium

In the Duff & Phelps online Cost of Capital Navigator (dpcostofcapital.com) there are two different valuation data sets, each of which includes beta-adjusted size premia that can be used as inputs when estimating the cost of equity capital: (i) the CRSP Size Premia Study, and (ii) the Risk Premium Report Study.[11] The size premia presented in both the studies are "beta-adjusted", and are calculated using the *same* methodological framework.[12] For simplicity, in this article we employ data from the CRSP Deciles Size Study in the examples presented.

Size premia are calculated here as the difference in historical portfolio excess returns (i.e., what *did happen*), and the excess returns that CAPM would have *predicted*. Excess returns are defined here as returns over and above the risk-free asset's returns. This is the same way that the size premia were calculated in the Ibbotson Associates/Morningstar *SBBI Valuation Yearbook* (1999–2013), the *Valuation Handbook—U.S. Guide to Cost of Capital* (2014–2017), and now in the online Cost of Capital Navigator (2018 and subsequent years).

First, let's examine the base (i.e., "textbook") CAPM equation to see what is meant by "excess returns that CAPM would have predicted". The base CAPM equation can be expressed as follows:[13]

Cost of equity = Risk-free Rate + (Beta x Equity Risk Premium)

Or notationally as:

$K_e = R_f + (ß \times RP_m)$

"Excess returns" are defined here as returns over and above the risk-free asset's returns. Anything added to the risk-free rate ("R_f" in the equation above) is by definition "over and above" the risk-free rate. In the base CAPM equation, "excess returns" is therefore represented by beta multiplied by the equity risk premium (in the equation this is "$ß \times RP_m$"):

$$K_e = R_f + \boxed{(ß \times RP_m)} \quad \text{excess return}$$

A problem with the base CAPM equation is that it is not very reliable in predicting the realized excess returns of small-cap companies. To demonstrate this, we can use the CAPM equation to decompose the average annual return of CRSP decile 10 (comprised of the smallest companies, as measured by market capitalization).[14]

In Exhibit 2, the average annual returns of CRSP NYSE/NYSE MKT/NASDAQ deciles 1–10 over the period 1926–2017 period for are shown. As size (in this case, as measured by market cap) decreases, the realized return tends to increase. For example, the average annual return of decile 1 (the largest-cap companies) was 11.19% over the 1926–2017 period, while the annual arithmetic mean returns of decile 10 (the smallest-cap companies) was 20.19%.

Note that this increased return comes at a price: risk (as measured by standard deviation) increases from 18.86% for decile 1 to 42.22% for decile 10. The increase in standard deviation of returns is correlated with the increase in the decile betas. The relationship between risk and return is a fundamental principle of finance and the framework to estimate cost of capital.

Exhibit 2: Summary Statistics of Annual Returns (CRSP NYSE/NYSE MKT/NASDAQ Deciles)

1926–2017

Decile	Beta	Arithmetic Mean (%)	Standard Deviation (%)
1-Largest	0.92	11.19%	18.86%
2	1.04	12.89%	21.37%
3	1.11	13.67%	23.24%
4	1.13	13.84%	25.42%
5	1.17	14.62%	26.03%
6	1.17	14.89%	26.97%
7	1.25	15.41%	28.87%
8	1.30	16.08%	32.84%
9	1.34	16.94%	36.97%
10-Smallest	1.39	20.19%	42.22%

Source of underlying data: CRSP U.S. Stock Database and CRSP U.S. Indices Database © 2018 Center for Research in Security Prices (CRSP®), University of Chicago Booth School of Business. CRSP NYSE/NYSE MKT/NASDAQ deciles 1–10. Used with permission. All rights reserved. Calculations performed by Duff & Phelps, LLC. To learn more about CRSP, visit crsp.com.

The predicted excess returns of CRSP decile 10 using the base CAPM equation can be calculated in the following fashion. Again, the base CAPM equation is:

Cost of equity = Risk-free Rate + (Beta x Equity Risk Premium), or

$K_e = R_f + (ß \times RP_m)$

To calculate the excess return of CRSP decile 10 using the base CAPM equation, we need a beta (*ß*) and an equity risk premium (RP_m):

- The beta (*ß*) of CRSP Decile 10 is 1.39
- The "historical" average annual long-term equity risk premium (RP_m) is 7.07%, calculated as the difference between the average annual total return of the S&P 500 total index (12.06%) and the average annual income return (4.99%) of a long-term (i.e., 20-year) U.S. Treasury bond (the "risk-free" asset).

The "excess return" ("$ß \times RP_m$" in the textbook CAPM equation) of CRSP decile 10 is therefore 9.84%:

Excess Return of CRSP Decile 10 = $ß \times RP_m = 1.39 \times 7.07\% = 9.84\%$ *(difference due to rounding)*[15]

To gauge how well the base CAPM equation did at predicting the excess returns of CRSP decile 10, we can compare the textbook CAPM equation estimate of what "should have happened" with what "actually happened".

Looking to Exhibit 2, the actual average annual return of CRSP decile 10 over the 1926–2017 period was 20.19%, and the average annual income return of a long-term (i.e., 20-year) U.S. Treasury bond (the "risk-free" asset) was 4.99%.

- The actual excess return of CRSP decile 10 is therefore 15.20% (20.19% –99%).
- The textbook CAPM equation estimate of excess returns for CRSP Decile 10 was 9.84%.

The textbook CAPM equation did not do a very good job of predicting the excess returns of CRSP decile 10, which is comprised of the smallest companies. The textbook CAPM equation estimate of what "should have happened" fell 5.37% (15.20% – 9.84%) short of what "actually happened".[16]

This analysis demonstrates why valuation professionals typically add a "size premium" to the base CAPM equation: the betas of small-cap companies do not fully account for the actual excess returns that are typically seen with small-cap companies. The 5.37% that the textbook CAPM equation fell short is assumed to be a function of "size", and is therefore added as a "beta-adjusted" size premium in the "modified" CAPM equation (MCAPM), which includes an adjustment for size:

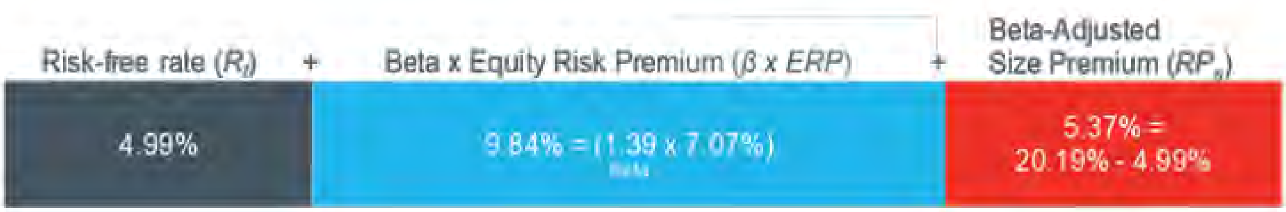
Cost of equity = Risk-free Rate + (Beta x Equity Risk Premium) + Size Premium, or

$$K_e = R_f + (\beta \times RP_m) + \boxed{RP_s} \quad \textit{beta-adjusted size premium}$$

The average annual return of CRSP Decile 10 is thus decomposed into three components using the modified CAPM: (i) the risk-free rate (4.99%), (ii) the excess returns predicted by the systematic risks measured by beta and the equity risk premium (9.84%), and (iii) the return in excess of what the textbook CAPM predicted (5.37%), also known as a beta-adjusted size premium. This decomposition is illustrated in Exhibit 3.

Exhibit 3: Decomposition of CRSP Decile 10 Average Annual Returns Using the Modified CAPM Equation

1926–2017

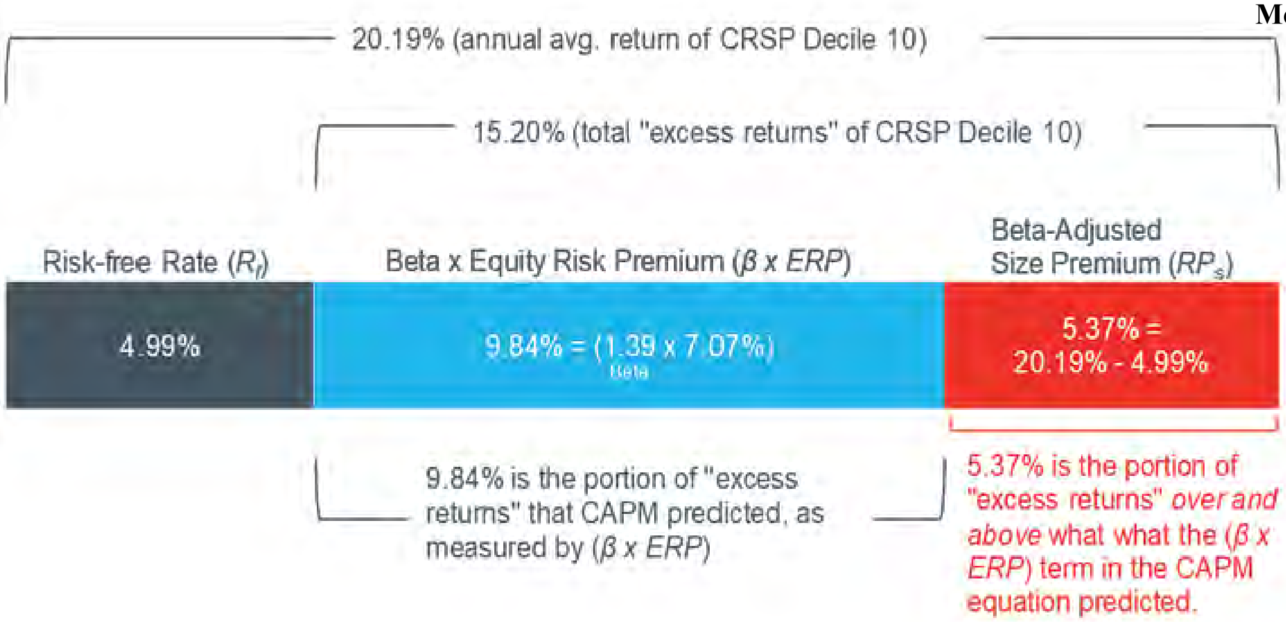


What Does "Beta-Adjusted" Mean?

A "beta-adjusted" size premium has been adjusted to remove the portion of excess return that is attributable to beta (within the context of the CAPM), therefore isolating the size effect's contribution to excess return. But what exactly does this mean? When we say we are "adjusting" (i.e., "controlling") for something, what we mean is that we want to exclude the influence of something from a calculation.

In Exhibit 4, the predicted excess return for CRSP decile 10 (9.84%) is calculated in the textbook CAPM equation by the beta multiplied by the equity risk premium (*β x ERP*). It follows that anything over and above what the base CAPM predicts (in this case, 5.37%) is (by definition) not the result of the risks embodied by the beta and equity risk premium. We can thus say that the 5.37% portion of excess returns is "beta-adjusted" within the framework of the CAPM equation.

Exhibit 4: CAPM Decomposition of the Annual Average Return of CRSP Decile 10 (20.19%) Over the Time Period 1926–2017



Why the Portion of Excess Returns Over and Above What CAPM Predicts is Attributed to "Size"

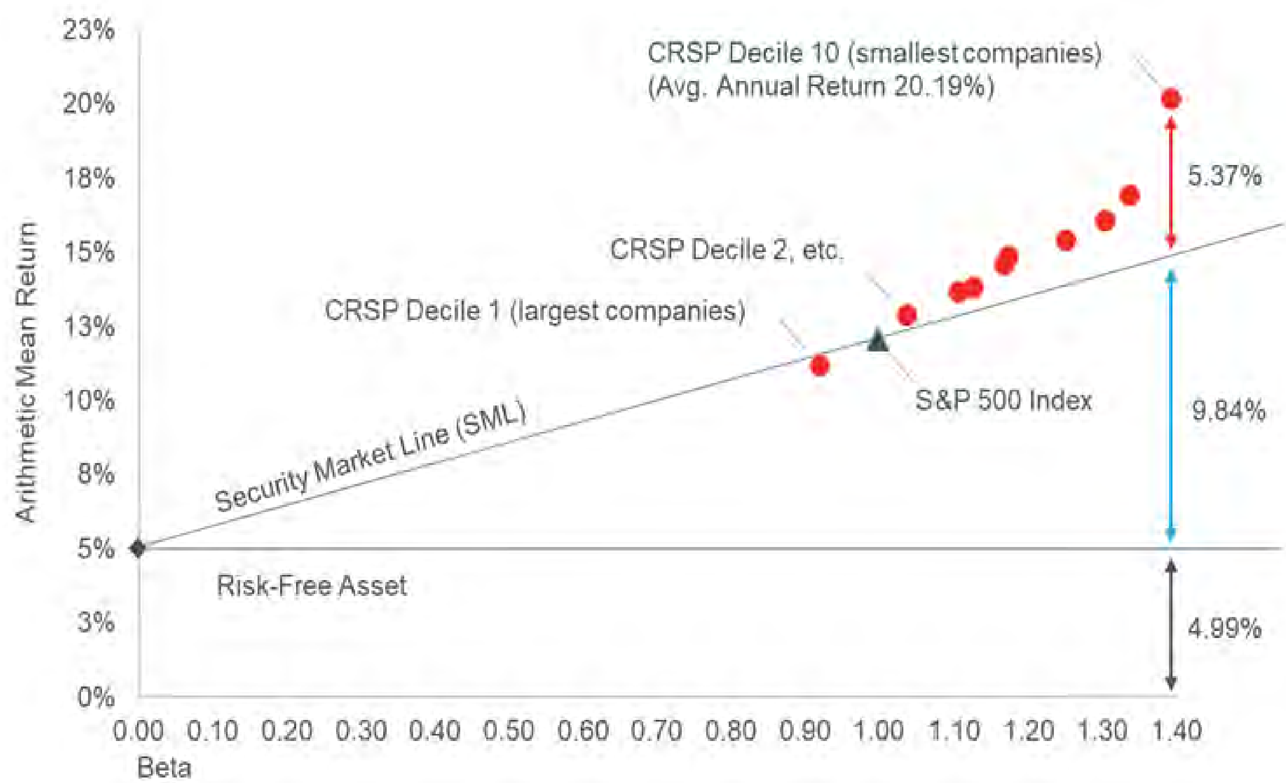
Exhibit 2 displays the betas, arithmetic average (i.e., "mean") annual return, and standard deviation of CRSP deciles 1–10, measured over 1926–2017. We noted in the discussion of Exhibit 2 that as size (in this case, as measured by market cap) decreases, return tends to increase.

Exhibit 5 depicts a "scatterplot" graph of the betas (horizontal axis) and average annual returns (vertical axis) from Exhibit 2 of each of the CRSP deciles 1–10. In the graph, the ten red dots represent CRSP deciles 1 (comprised of the largest companies) through CRSP decile 10 (comprised of the smallest companies), and the dark gray triangle is the "market" benchmark (the S&P 500 Index; beta = 1.00).

The security market line (SML) in Exhibit 5 represents what the textbook CAPM equation (without an adjustment for size) predicts as the excess return for each of the CRSP deciles, dependent on the respective levels of systematic risk (beta) for each. Note that the textbook CAPM equation does not do a very good job of predicting the realized excess return of the deciles, which fall increasingly above the security market line as size decreases. This indicates that these deciles have returns in excess of what their systematic risk implies. Another way of saying this is that within the context of the CAPM, the betas of small-cap companies do not fully account for (or explain) their actual returns. Because the amount of this difference (what actually happened versus what CAPM predicted) varies with "size" (in this case, as measured by market capitalization) we call it a "size premium". It is not clear, however, whether this is due to size itself, or to other factors closely related to or correlated with size. [17]

We previously used the CAPM equation to decompose the average annual return of CRSP decile 10 from 1926 through 2017 (20.19%) into (i) the return on a risk-free asset (4.99%), (ii) the excess returns predicted by the textbook CAPM (9.84%), and (iii) excess return over and above what CAPM predicted (5.37%), which represents the "beta-adjusted size premium" for Decile 10 as of December 31, 2017. For a different perspective (and aid in understanding this concept), these values (4.99%, 9.84%, 5.37%) have been included in Exhibit 5.

Exhibit 5: Security Market Line versus CRSP Deciles 1–10; 1926–2017



The Potential Danger of Using a *Non-Beta-Adjusted* Size Premium in the Context of the CAPM to Estimate Cost of Equity Capital

To answer this question, revisit the earlier discussion about the calculation of the "small stock premium". The small stock premium is related to the beta-adjusted size premium, insofar as each contains information about the relative performance of small-cap versus large-cap stocks. However, they are not interchangeable as far as usage.

As previously discussed, for forward-looking long-term forecasting purposes, the small stock premium is typically calculated as the simple difference in the average annual returns of small stocks and large stocks.

Earlier in this article we calculated a small stock premium in this fashion using the Ibbotson Associates "Large Company Stocks" series (which is essentially the S&P 500 index) and "Small Company Stocks" series that have traditionally been used in the Ibbotson

Associates/Morningstar *SBBI Yearbook* for such calculations.[18] In the following section, an equivalent calculation of a long-term “small stock premium” for forecasting purposes can be accomplished using the S&P 500 index as the market benchmark, but this time with CRSP decile 10 as the proxy for “small stocks”. [19],[20]

Calculating a Small Stock Premium (i.e., a Non-Beta-Adjusted Size Premium) Using CRSP

Decile 10

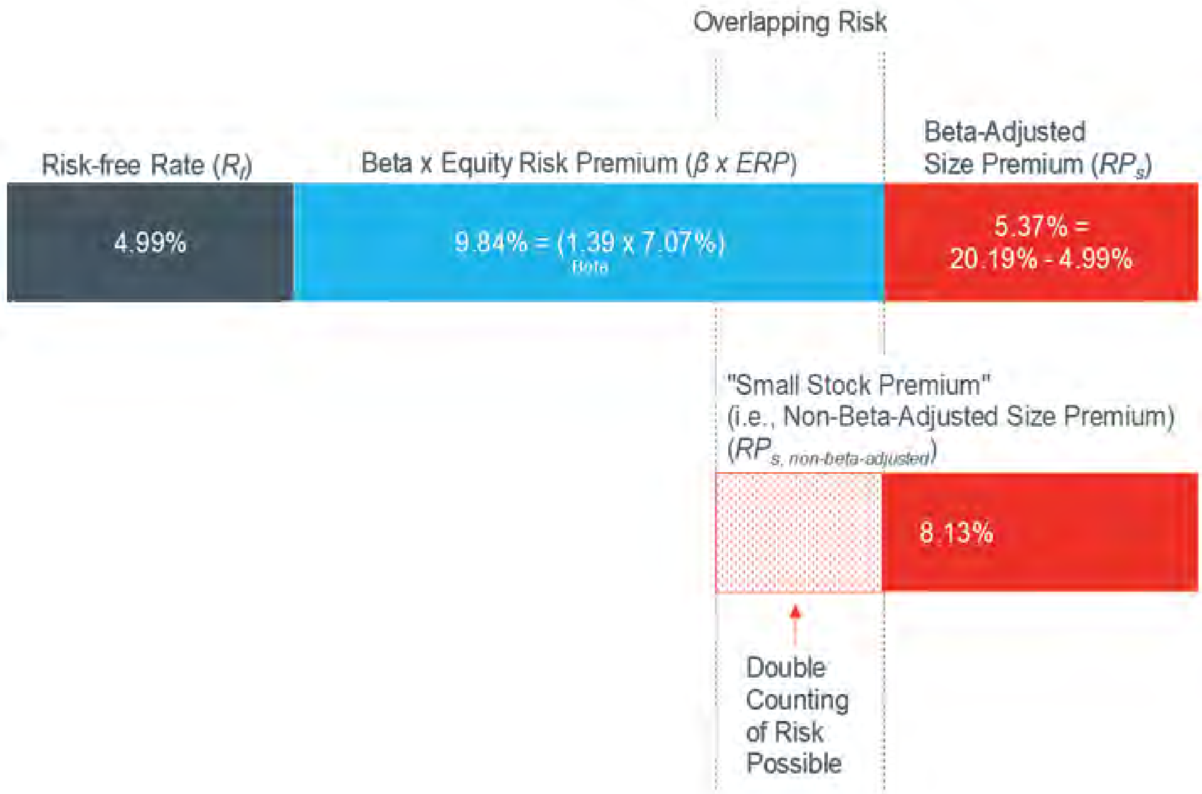
A small stock premium for CRSP decile 10 can be calculated as the simple difference between the average annual return of the market benchmark (in this case, the S&P 500 index) from 1926–2017, and the average annual return of CRSP Decile 10 over the same time period. The average annual return of large stocks (as measured by the S&P 500 total return index) from 1926 through 2017 was 12.06%, and the average annual return of small stocks (as measured by CRSP decile 10) over the same period was 20.19%, implying a “small stock premium” of 8.13% (20.19% – 12.06%).

The result of this calculation is effectively a “non-beta-adjusted” size premium.

Potential of Double Counting Risk

Compare this non-beta-adjusted size premium result (8.13%) to the beta-adjusted size premium result (5.37%) previously developed for CRSP decile 10. The non-beta-adjusted size premia for CRSP decile 10 is larger than the beta-adjusted size premia by 2.76% (8.13% – 5.37%). This is likely because some risks being measured in the small stock premium *overlap* with systematic risks already being measured within the context of the CAPM in the term where beta is multiplied by the equity risk premium (β *x ERP*). This “double counting” of risk is illustrated in Exhibit 6.

Exhibit 6: CAPM Decomposition of the Annual Average Return of CRSP Decile 10 (1926–2017)



As illustrated in Exhibit 6, using the small stock premium (i.e., a non-beta-adjusted size premium) in the context of the CAPM to estimate cost of equity capital will likely overstate risk, and thus understate value.

In pre-1995 versions of the Ibbotson Associates *Stocks, Bonds, Bills, and Inflation® (SBBI®) "Classic" Yearbook*, the book actually did suggest that the "small stock premium" could be added to the CAPM as a size adjustment to the CAPM. That changed in the 1995 version of that book, when Ibbotson Associates began "beta-adjusting" the size premia they published, stating, "The size premia given here (…) are adjusted for beta. That is, small stocks do have higher betas than large stocks; the return, above what might be expected because of the higher betas, is the size premia. These size premia increase as the capitalization of the company decreases."[21]

In 1999, Ibbotson Associates used the single chapter dedicated to valuation issues in the *SBBI® "Classic" Yearbook* and used it as the basis for a new "yearbook" dedicated solely to valuation issues, the *Stocks, Bonds, Bills, and Inflation® (SBBI®) "Valuation" Yearboo*k. That book provided significantly expanded commentary and analysis of valuation issues, plus "Key Variables in Estimating the Cost of Capital", which included size premia and other valuation inputs.

Can a Non-Beta-Adjusted Size Premium Be used With the Build-Up Method?

Thus far the discussion has been focused on the use of beta-adjusted size premia within the context of the modified CAPM (MCAPM), and the potential for double-counting risk if the "small stock premium" (i.e., a non-beta-adjusted size premium) is used.

A non-beta-adjusted size premium should not be used in "build-up" methods of estimating cost of capital that employ an industry risk premium and a size premium together in the same equation. The reason is that the MCAPM equation and the equation of a build-up method that employs an industry risk premium and a size premium are exactly equivalent. In other words, this formulation of the build-up method is merely the MCAPM with the terms re-arranged.

To understand why, it is important to appreciate that an industry risk premium is simply a beta that has been modified so that it can be added as a simple "up or down" adjustment in a build-up method of estimating cost of equity capital (i.e., an additive risk adjustment in the equation). Industry risk premia are calculated as follows:

Industry Risk Premium = RP_i = (Beta x Equity Risk Premium) – Equity Risk Premium, or

$RP_i = (ß \times RP_m) - RP_m$

One of the variations of the build-up method can be expressed as the following equation:

$K_e = R_f + RP_m + RP_i + RP_s$

To demonstrating algebraically that the MCAPM and this formulation of the build-up method are equivalent, we can substitute the Industry Risk Premium equation (above) into the build-up equation for the term "RP_i", and we obtain the following:

$K_e = R_f + RP_m + (ß \times RP_m - RP_m) + RP_s$

We can then simplify the equation further, as the positive and negative RP_m factors cancel out:

$K_e = R_f + RP_m + (ß * RP_m - RP_m) + RP_s$

Which simplifies to the MCAPM equation:

$K_e = R_f + ß * RP_m + RP_s$

Because a build-up equation that employs an industry risk premium and a size premium is the exact equivalent of the MCAPM equation, a beta-adjusted size premium must also be used in conjunction with this formulation of the build-up method. If a non-beta-adjusted size premium is used, it will likely embody risks that overlap with systematic risks already being measured within the context of the build-up (just as in the MCAPM), and thus "double-count" these risks.

Conclusion

The small stock premium *is* related to the beta-adjusted size premium, insofar as each contains information about the relative performance of small-cap versus large-cap stocks. However, they are *not* interchangeable as far as usage. Using a non-beta-adjusted size premium in the context of the MCAPM (or a build-up method that includes an industry risk premium) to estimate cost of equity capital will likely *overstate* risk and *understate* value. As elegantly summarized in the inaugural Ibbotson Associates *Stocks, Bonds, Bills, and Inflation® (SBBI®) "Valuation" Yearboo*k in 1999:

"The non-beta-adjusted size premia already account for the added return generally attributed to the higher betas of small companies. Again, the non-beta-adjusted size premium makes the assumption that the beta of the company is the same as the small stock portfolio. If the non-beta-adjusted size premium is used in the context of the modified CAPM equation…the effect of beta on return will essentially be counted double. Multiplying the equity risk premium by another measure of beta (either the company beta or industry beta) introduces to the same equation a duplicate, though possibly different, measure of systematic risk."

– Roger Ibbotson, *1999 Stocks, Bonds, Bills, and Inflation® (SBBI®) Valuation Yearboo*k (Ibbotson Associates, Chicago), page 23.

[1] Roger Ibbotson is Chairman and Chief Investment Officer of Zebra Capital Management (www.zebracapm.com), Professor in the Practice Emeritus of Finance at Yale School of Management, and former Chairman of Ibbotson Associates and Ibbotson Associates Advisors, LLC until both were acquired by Morningstar Inc. in March 2006. He has written numerous books and articles including *Stocks, Bonds, Bills, and Inflation* with Rex Sinquefield (updated annually) which serves as a standard reference for information on capital market returns. He has published The *Equity Risk Premium* with William Goetzmann and *Lifetime Financial Advice* with Milevsky, Chen, and Zhu. He has also co-authored two books with Gary Brinson, *Global Investing and Investment Markets*. In addition, he has co-authored a textbook with Jack Clark Francis, *Investments: A Global Approach*. He is the recipient of many awards including Graham and Dodd Scrolls in 1979, 1982, 1984, 2001, 2004, 2007, 2011, 2012, and best *Financial Analysts Journal* article of 2013. He received the Harry M. Markowitz Award for "Momentum, Acceleration, and Reversal", the 2015 best paper in the *Journal of Investment Management*. Most recently (2019), Ibbotson and colleagues Thomas M. Idzorek, CFA, Paul D. Kaplan, CFA, and James X. Xiong, CFA published a new Chartered Financial Analyst® (CFA) Institute Research Foundation monograph entitled "Popularity: A Bridge Between Classical and Behavioral Finance" (available for download at https://www.cfainstitute.org/en/research/foundation/2018/popularity-bridge-between-classical-and-behavioral-finance). Professor Ibbotson served on numerous boards, and currently serves as a disinterested director, Chairman of the Audit Committee and member of the Nominating Committee of Dimensional Investment Group Inc. (DIG) and DFA

Investment Dimensions Group Inc. (DFAIDG), registered investment companies for which Dimensional Fund Advisors Inc. serves as investment adviser. He frequently speaks at universities, conferences, and other forums. He received his bachelor degree in mathematics from Purdue University, his MBA from Indiana University, and his PhD from the University of Chicago where he taught for more than ten years and served as Executive Director of the Center for Research in Security Prices.

[2] James P. Harrington is a Director at Duff & Phelps. James is a leading contributor to Duff & Phelps' efforts in the development of studies, surveys, online content and tools, firm-wide valuation models, data distribution platforms, and published thought leadership. James is a co-author of the Duff & Phelps "Valuation Handbook" series and a developer of the online "Cost of Capital Navigator" platform (dpcostofcapital.com), along with colleagues Roger Grabowski and Carla Nunes.

[3] For a detailed discussion, see the *2018 Stocks, Bonds, Bills, and Inflation® (SBBI®) Yearbook*, Chapter 10, "Using Historical Data in Wealth Forecasting and Portfolio Optimization". To learn more about or purchase the *SBBI® Yearbook*, visit: duffandphelps.onfastspring.com/books.

[4] The base (i.e., "textbook") CAPM equation is Cost of Equity = (Risk-free Rate) + (Beta) x (Equity Risk Premium), or notationally expressed as $K_e = R_f + ß \times RP_m$. When a size adjustment is added, this becomes Cost of Equity = (Risk-free Rate) + (Beta) x (Equity Risk Premium) + (Size Premium), or notationally expressed as $K_e = R_f + ß \times RP_m + RP_s$. This modified CAPM equation is often referred to as "modified CAPM" or MCAPM.

[5] Morningstar previously published two "Ibbotson SBBI®" yearbooks: (i) The *SBBI® "Classic" Yearbook*, which is now produced by Duff & Phelps as the "SBBI® Yearbook" starting in 2016 (the word "Classic" was dropped from the title), and (ii) the *SBBI® "Valuation"* Yearbook, which was discontinued by Morningstar in 2013. The former Ibbotson Associates/Morningstar *SBBI® Valuation Yearbook* was replaced by the Duff & Phelps *Valuation Handbook—U.S. Guide to Cost of Capital* in 2014, which was published annually as a hardcover book through 2017. Starting in 2018, Duff & Phelps does not publish a physical version of the *Valuation Handbook—U.S. Guide to Cost of Capital;* the essential valuation data from the data exhibits are available *only* in the Cost of Capital Navigator online platform at dpcostofcapital.com. The major difference between the *SBBI Yearbook* (the former "Classic" yearbook) and other Duff & Phelps data resources (e.g., the online Cost of Capital Navigator) is that Duff & Phelps' other data resources provide U.S. and international equity risk premia, risk-free rates, size premia, industry risk premia, betas, industry multiples and other statistics, etc., for use in valuation models, while the *SBBI® Yearbook* is (i) a history of the asset class returns of U.S. capital markets (thus the name, "Stocks, Bonds, Bills, and Inflation®," or "SBBI®") from 1926 to the present, and (ii) an analysis of the relative performance of U.S. asset classes. The *SBBI® Yearbook* does not provide extensive valuation data or methodology. To learn more about or purchase the *Stocks, Bonds, Bills, and Inflation®*

(SBBI®) Yearbook, visit: duffandphelps.onfastspring.com/books.

[6] In the *2018 SBBI® Yearbook*, the Ibbotson Associates SBBI U.S. Small Stock total return series (i.e., "IA SBBI US Small Stock TR USD") is represented by: (i) the DFA U.S. Micro Cap Portfolio from April 2001 through December 2017, (ii) the DFA U.S. 9–10 Small Company Portfolio from January 1982 through March 2001, and (iii) the NYSE Fifth Quintile Returns from 1926 through 1981. The Ibbotson Associates SBBI U.S. Large Stock total return series (i.e., "IA SBBI US Large Stock TR USD Ext") is based upon the S&P Composite Index. This index is a readily available, carefully constructed, market-capitalization-weighted benchmark of large-cap stock performance. Market-capitalization-weighted means that the weight of each stock in the index, for a given month, is proportionate to its market capitalization (price times the number of shares outstanding) at the beginning of that month. Currently, the S&P Composite includes 500 of the largest stocks (in terms of stock market value) in the U.S.; prior to March 1957 it consisted of 90 of the largest stocks. From February 1970 to the present, the large-cap stock total return is provided by S&P Dow Jones Indices, which calculates the total return based on the daily reinvestment of dividends on the ex-dividend date. S&P uses closing pricing from stock exchanges in its calculation. Prior to February 1970, the total return for a given month was calculated by summing the capital appreciation return and the income return The capital appreciation component of the large-cap stock total return is the change in the S&P 500 index as reported by S&P Dow Jones Indices from March 1928 to December 2017, and in Standard & Poor's *Trade and Securities Statistics* from January 1926 to February 1928. From February 1970 to December 2017, the income return was calculated as the difference between the total return and the capital appreciation return. From January 1926 to January 1970, quarterly dividends were extracted from rolling yearly dividends reported quarterly in S&P's *Trade and Securities Statistics*, then allocated to months within each quarter using proportions taken from the 1974 actual distribution of monthly dividends within quarters.

[7] "Small Stock" in this context refers to a specific data series created by Ibbotson Associates to represent smaller market capitalization (i.e., small-cap) stocks. "Small-cap" stocks can be represented in a variety of ways, including the aforementioned Ibbotson Associates "small stock" series, or the CRSP 10th decile (as is done later in this article).

[8] The small stock premium is calculated arithmetically here. Arithmetic calculation of premia is typically done when developing forward-looking long-term inputs for MVO analyses, wealth forecasting, or discount rates. The small stock premium can also be calculated on a geometric basis as (1+Small Stock Total Return) ÷ (1+Large Stock Total Return) –1. See: *2018 Stocks, Bonds, Bills, and Inflation® (SBBI®) Yearbook*, Chapter 4, "Description of the Derived Series", page 4-2. To learn more about or purchase the *Stocks, Bonds, Bills, and Inflation® (SBBI®) Yearbook,* visit: duffandphelps.onfastspring.com/books.

[9] Small-cap companies do not always outperform large-cap companies. However, as the holding period is increased, small-cap companies tend to outperform large-cap companies to an increasingly greater degree. In other words, the *longer* small-cap companies are given to "race" against large-cap companies, the greater the chance that small-cap companies outpace their larger counterparts. For a detailed discussion of this concept, see the Cost of Capital Navigator "Resources" section, *2018 Valuation Handbook—U.S. Guide to Cost of Capital*, Chapter 4, "Basic Building Blocks of the Cost of Equity Capital – Size Premium". Duff & Phelps © 2018. Available at dpcostofcapital.com.

[10] The result of this calculation can vary dependent on the series selected to represent large-cap and small-cap stocks. For example, later in this article a small stock premium is calculated over the same time horizon (1926–2017) using the same measure of large-cap stocks (the S&P 500 total return index), but a different measure of small-cap stocks (the CRSP 10th decile). The result of that calculation yields a result of 8.13% (see section entitled "Calculating a Small Stock Premium (i.e., a Non-Beta-Adjusted Size Premium) Using CRSP Decile 10".

[11] "Premia" is the plural of "premium".

[12] For a detailed discussion of the CRSP Size Premia Study, and the Risk Premium Report Study, see the Cost of Capital Navigator "Resources" section, *2018 Valuation Handbook—U.S. Guide to Cost of Capital*, Chapter 7, "The CRSP Decile Studies and the Risk Premium Report Studies—A Comparison". Duff & Phelps © 2018. Available at dpcostofcapital.com.

[13] Finance professionals use the term equity risk premium interchangeably with market risk premium (MRP, or RP_m) and equity market risk premium (EMRP).

[14] The Center for Research in Securities Prices (CRSP) constructs 10 market-capitalization-weighted deciles that are then sorted by market cap. CRSP decile 1 is comprised of the largest companies, and CRSP decile 10 is comprised of the smallest companies. The CRSP deciles are comprised of publicly traded U.S. companies from the NYSE, the NYSE MKT, and the NASDAQ exchanges. To learn more about CRSP, visit www.CRSP.com. The CRSP standard market-capitalization-weighted deciles were used to calculate size premia in Ibbotson Associates/Morningstar *SBBI® Valuation Yearbook* (1999–2013), the Duff & Phelps *Valuation Handbook—U.S. Guide to Cost of Capital* (2014–2017), and now in the online Cost of Capital Navigator (2018 and subsequent years) at dpcostofcapital.com.

[15] Difference due to rounding. Using two decimals of precision (as shown here), the result is 9.83% (1.39 x 7.07%). However, using full precision (i.e., all decimals), this result is 9.84%. We note this because "9.84%" is the actual value used as of December 31, 2017 in these calculations as published in the Cost of Capital Navigator at dpcostofcapital.com.

[16] Difference due to rounding. Using two decimals of precision (as shown here), the difference is 5.36% (15.20% – 9.84%). However, using full precision (i.e., all decimals), the difference is 5.37%. We note this because "5.37%" is the actual size premia calculated for CRSP Decile 10 as of December 31, 2017, as published in the Cost of Capital Navigator at dpcostofcapital.com.

[17] See: Roger J. Grabowski (*2018*) The Size Effect Continues to Be Relevant When Estimating the Cost of Capital. *Business Valuation Review: Fall 2018*, Vol. 37, No. 3, pp. 93-109. See also: Roger G. Ibbotson and Daniel Y.-J. Kim, "Risk and Return within the Stock Market: What Works Best?" working paper, January 8, 2016. Available at www.zebracapital.com.

[18] The *SBBI® Yearbook* has been published for over 30 years. The *SBBI® Yearbook* does not provide extensive valuation data or methodology. The *SBBI® "Classic" Yearbook* was published by Morningstar, Inc. from 2007 through 2015, and by Ibbotson Associates in years prior to 2007. Starting with the 2016 edition, the *Stocks, Bonds, Bills, and Inflation® (SBBI®) Yearbook* has been produced by Duff & Phelps (the word "Classic" was dropped from the book's title). To learn more about or purchase the *Stocks, Bonds, Bills, and Inflation® (SBBI®) Yearbook,* visit: duffandphelps.onfastspring.com/books.

[19] Our previous discussion of the small stock premium was in the context of the traditional way this statistic has been calculated in the *Stocks, Bonds, Bills, and Inflation (SBBI) "Classic" Yearbook*, and so the Ibbotson Associates Small Company Stock total return index was used as the proxy for small-cap stocks for that calculation, as is done in that book. In this section, however, we are discussing the small stock premium and beta-adjusted size premia in the context of the CRSP deciles, and so a different proxy for small stocks is necessarily being used (CRSP decile 10).

[20] An equivalent calculation can be accomplished using any of the ten CRSP deciles; for the examples in this section we will develop a small stock premium for CRSP decile 10 to facilitate easy comparison to our earlier development of a beta-adjusted size premium for CRSP decile 10.

[21] Roger, G. Ibbotson, *1995 Stocks, Bonds, Bills, and Inflation® (SBBI®) Yearbook* (Ibbotson Associates, 1995), Chapter 8, "Estimating the Cost of Capital or Discount Rate", page 155.

Roger G. Ibbotson is Professor in the Practice Emeritus of Finance at Yale School of Management. He is also chairman and CIO of Zebra Capital Management, LLC, an equity investment and hedge fund manager. He is founder, advisor and former chairman of Ibbotson Associates, now a Morningstar Company. He has written numerous books and articles including Stocks Bonds Bills and Inflation with Rex Sinquefield (updated annually) which serves as a standard reference for information and capital market returns.

Professor Ibbotson conducts research on a broad range of financial topics, including popularity, *liquidity, investment returns, mutual funds, international markets, portfolio management, and valuation. He has recently published The Equity Risk Premium and Lifetime Financial Advice. He has also co-authored two books with Gary Brinson, Global Investing and Investment Markets. He is a regular contributor and editorial board member to both trade and academic journals.*

Professor Ibbotson serves on numerous boards including Dimensional Fund Advisors' funds. He frequently speaks at universities, conferences, and other forums. He received his bachelor's degree in mathematics from Purdue University, his MBA from Indiana University, and his PhD from the University of Chicago where he taught for more than ten years and served as executive director of the Center for Research in Security Prices.

Professor Ibbotson can be contacted at roger.ibbotson@yale.edu.

James P. Harrington is a Director at Duff & Phelps. He is a leading contributor to Duff & Phelps' efforts in the development of studies, surveys, online content and tools, firm-wide valuation models, data distribution platforms, and published thought leadership. Mr. Harrington is a co-author of the Duff & Phelps "Valuation Handbook" series and a developer of the online "Cost of Capital Navigator" platform (dpcostofcapital.com), along with colleagues Roger Grabowski and Carla Nunes.

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LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 76

Responding Witness: Adrien M. McKenzie

Q-76. Refer to McKenzie Testimony, Exhibit No. 8. Explain whether the average utility bond yields on page 3 of 4 are Baa rated utility bond yields and whether they are the same bonds as represented in Average Utility Bond Yields of 3.10 percent and 4.12 percent listed on pages 1 of 4 and 2 of 4 respectively. If not:

a. For page 1 of 4, show the calculation in footnote (b), and explain why it is reasonable to average the yield on all utility bonds and a specific subset for a current average utility bond yield of 3.01 percent, and why that difference can be applied to a different specific bond subset.

b. For page 2 of 4, show the calculation in footnote (b), and explain why it is reasonable to average the yield on all utility bonds and a specific subset for a forecasted average utility bond yield of 4.12 percent, and why that difference can be applied to a different specific bond subset.

c. For pages 1 of 4 and 2 of 4, explain why different bond subsets (Baa and A) were used in the calculations described in footnote (b).

d. Refer to McKenzie Testimony, Table 4, page 60. Explain whether the bond data listed in the table are the same as used in Exhibit No. 8, page 1 of 4 and page 2 of 4.

e. Provide a copy of the source documents for Table 4.

A-76.

a. Calculations underlying the average utility bond yield of 3.01% and the average yield on Baa utility bonds of 3.37% are contained at tab "Bond Yields" in the Excel File identified as " 2020_Att_KU_LGE_PSC_1-56_Exhibit_McKenzie_2-12.xlsm " which is provided in response to PSC 1-56. The average yield on all utility bonds was used as the basis for developing the adjusted risk premium because this measure best reflects the average ratings of the utility industry over the long historical horizon of the study period. To better reflect the average risks of this proxy group, the adjusted risk premium was combined with the current average yield on Baa-rated utility bonds to compute the estimated cost of equity.

b. Calculations underlying the average projected utility bond yield of 4.45% and the average projected yield on Baa utility bonds of 5.09% are contained at tab "Bond Yields" in the Excel File identified as "2020_Att_KU_LGE_PSC_1-56_Exhibit_McKenzie_2-12.xlsm" which is provided in response to PSC 1-56. Please refer to the response to subpart (a) regarding the use of the average utility bond yields and Baa subset.

c. As indicated in footnote (b) to pages 1 and 2 of Exhibit No. 8, the bond yield averages refer to those for all utility bonds and Baa-rated utility bonds. Please refer to the response to subpart (a), which explains why different bond subsets were used in the calculations.

d. No. Table 4 presents average forecasted yields on 10-year and 30-year Treasury bonds, Aaa-rated corporate bonds, and Aa-rated utility bonds based on published projections from the cited sources. The bond yields referenced in Exhibit No. 8, page 1 of 4 are six-month average yields on public utility bonds rated Aa, A, and Baa, as well as six-month average yields on Baa-rated utility bonds. Page 2 of 4 of Exhibit No. 8 references projected yields over the 2021-2025 time period for public utility bonds rated Aa, A, and Baa, as well as Baa-rated utility bonds. The derivation of these projected yields is provided at tab "Bond Yields" in the Excel File identified as " 2020_Att_KU_LGE_PSC_1-56_Exhibit_McKenzie_2-12.xlsm" which is provided in response to PSC 1-56.

e. The source documents for Table 4 are provided as files "WP-31," "WP-32," "WP-34," and "WP-35," to Mr. McKenzie's workpapers, which are provided in response to PSC 2-67.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 77

Responding Witness: Adrien M. McKenzie

Q-77. Refer to McKenzie Testimony, Exhibit No. 8, page 3 of 4. Confirm that over the 45-year study period, the data in the Allowed ROE column is based upon state jurisdictional electric or electric and gas combination utilities only. If not, explain what other types of utilities are included in the data set.

A-77. Confirmed.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 78

Responding Witness: Adrien M. McKenzie

Q-78. Refer to McKenzie Testimony, page 62, lines 5–23, through page 63, lines 4–13.

a. Explain why the argument put forth in the testimony opposing the use of quarterly ROE observations is not also applicable to the use of annual average ROEs.

b. Confirm that each annual average observation used in Exhibit No. 8 is comprised of individual and, hence, quarterly awarded ROE observations.

A-78.

a. Mr. McKenzie's testimony at page 63, lines 4-13 addresses this issue. As explained there, consideration of the entire available data set over a 44-year horizon is not unduly influenced by the circumstances specific to an isolated statistic based on a single calendar quarter. In addition, the risk premium analyses presented in Exhibit No. 8 accounts for the impact of changes in capital market conditions by adjusting equity risk premiums for the empirical relationship with bond yields.

b. The annual average allowed ROEs reported in RRA Regulatory Focus are based on the ROEs allowed in individual rate proceedings during each calendar year. Quarterly average ROE observations are based on similar data, but limited to a specific quarterly period.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 79

Responding Witness: Adrien M. McKenzie

Q-79. Refer to McKenzie Testimony, page 67, lines 4–24, through page 68, lines 1–8.

a. Explain whether and how flotation costs are recovered such that investors who invest in nonregulated competitive industries have the opportunity to earn their required ROE.

b. Explain the extent to which investors' required ROEs for holding company stock are influenced by the nonregulated operations of holding companies, which include regulated utilities, such as LG&E and KU.

A-79.

a. Unlike regulated utilities, firms in the competitive sector are not regulated on the basis of the book value of their investment and are free to set their own prices, subject to market forces. As a result, the fact that a portion of stock proceeds is not reflected in rate base or otherwise accounted for in the revenue requirements used to establish prices has no direct relevance in the nonregulated sector.

b. While the firms included in Mr. McKenzie's proxy group are regarded by the investment community as primarily regulated utilities, investors' required ROEs for holding company stocks would consider the risks and expectations for both regulated and unregulated operations.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 80

Responding Witness: Christopher M. Garrett

Q-80. Refer to the Direct Testimony of Christopher M. Garrett (Garrett Testimony), page 23, lines 23–24, and page 24, line 1. For the uncollectable account percentages, explain how LG&E accounted for the moratorium on disconnections from Case No. 2020-00085.[21]

A-80. LG&E did not account for the moratorium on disconnections from Case No. 2020-00085 in the uncollectable account percentages for the forecasted test period.

As discussed in the Direct Testimony of Kent W. Blake (page 5, lines 17-21, and page 6, lines 1-6), KU and LG&E are using a 5-year historical average (2015-2019) which does not reflect the COVID-19 pandemic and resulting recession. This decision resulted in a reduction in the revenue requirements in this proceeding of $5.1 million (KU $2.2 million, LG&E Electric $2.4 million, and LG&E Gas $0.5 million). The Companies recognize there is uncertainty around the ultimate size of the expected increase in bad debts with the moratorium on disconnects having just been lifted last month. In the event the Companies ultimately experience any significant increase in bad debt expense resulting from restrictions put in place during the 2020 pandemic, the Companies would expect to file, and the Commission to fairly consider, a request for a regulatory asset for any expenses significantly beyond that embedded in base rates during these proceedings.

[21] Case No. 2020-00085, *Electronic Emergency Docket Related to the Novel Coronavirus COVID-19*, (Ky. PSC filed Mar. 16, 2020).

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 81

Responding Witness: Robert M. Conroy

Q-81. Refer to the Direct Testimony of Robert M. Conroy (Conroy Testimony), page 9, lines 21–23. LG&E proposed to make a post-case filing ten days prior to the effective date of the true-up charge or credit through the post-case filing.

a. Explain if LG&E would file the true-up through the Commission's electronic tariff filing system.

b. Explain why LG&E would not file at least 30 days prior given the proposed true up month is 90 days after the completion of the proposed surcredit.

A-81.

a. Consistent with other adjustment clause filings that do not require tariff updates to reflect the current billing factor (e.g., FAC, OSS, and ECR), LG&E proposes making a post-case filing in this proceeding in order to document the calculation of the true-up charge or credit.[22] Because the Commission has the opportunity to approve the methodology being used to calculate the true-up in this proceeding, this filing is simply an informational update to the Commission that provides the results of the true-up calculations.

b. Because LG&E does not consider this to require a tariff filing and other adjustment clause filings require LG&E to file supporting documentation for changes in billing factors at least 10 days prior to the effective date, LG&E proposes to follow the same filing requirement as its other adjustment clauses.[23] See also the response to Question No. 82.

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[22] *See* 807 KAR 5:056 Sec. 2(4) ("The monthly fuel adjustment shall be filed with the commission no later than ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustment."); Louisville Gas and Electric Company, P.S.C. Electric No. 12, Original Sheet No. 88 ("The combined monthly FAC and OSS factor shall be filed with the Commission ten (10) days before it is scheduled to go into effect[.]"); KRS 278.183 ("The amount of the monthly environmental surcharge shall be filed with the commission ten (10) days before it is scheduled to go into effect[.]").

[23] *Id.*

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 82

Responding Witness: Robert M. Conroy

Q-82. Refer to the Conroy Testimony, page 10, lines 5–7. Explain why LG&E choose the true-up period to occur in the 15th month, 90 days after the completion of the proposed surcredit.

A-82. The timing of the true-up calculation was determined based on when the billing cycle will be complete for the last month of the 12-month period during which the Economic Relief Surcredit will be effective. In other words, if the initial Economic Relief Surcredit terminates effective with services rendered July 1, 2022, customer billing cycles that overlap this time period must have time to complete before the last of the initial Economic Relief Surcredit is credited to customer bills (expected to be the end of August 2022, which is the 13th month). In the 14th month (expected to be September 2022), LG&E will then have access to all of the billing information needed to calculate the total amount of the initial Economic Relief Surcredit credited to customers and make the post-case filing 10 days prior to the effective date of the true-up charge or credit. The effective date coincides with the first day of the first billing cycle in the 15th month (expected to be October 2022).

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 83

Responding Witness: Robert M. Conroy

Q-83. Refer to the Conroy Testimony, page 15, lines 9–21. For the proposed Environmental Cost Recovery (ECR) project eliminations, confirm that these projects will now receive rate recovery based upon the approved WACC in this case, as opposed to the lowered WACC of limited rider mechanisms, and would no longer be subject to the true-up mechanism of the ECR tariff.

A-83. Confirmed. For clarity, if the question is referring to WACC with respect to the authorized return on equity for base rates compared to the authorized return on equity for ECR projects, it is important to note that the ECR projects proposed to be eliminated in this proceeding are currently authorized for the same return on equity as current base rates. Also of importance is that the WACC for ECR purposes changes periodically as a result of ECR review case proceedings. While the authorized return on equity does not change without Commission approval, the capital structure and cost of debt could vary in ECR review proceedings. Thus, the WACC used in the ECR tariff could be higher or lower than that used to establish base rates.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 84

Responding Witness: Robert M. Conroy

Q-84. Refer to the Conroy Testimony, page 15-16, regarding ECR projects. Explain whether LG&E's proposal to remove the test-year ECR base rate revenue requirement from the ECR revenue requirement would effectively true-up LG&E's base rates until the next two-year review.

A-84. For the ECR projects proposed to be eliminated, the portion of ECR revenue requirement currently collected as a component of base rates (either in energy or demand depending on the rate class) as the result of prior ECR "roll-ins" from two-year ECR review proceedings is net neutral from a base rate perspective. The component of base rates previously assigned as ECR revenue will now be reflected solely as base rate revenue to offset the costs now included in the base rate revenue requirement and thus will not be subject to the true-up mechanism of the ECR tariff. For the ECR expense month filing coinciding with the change in base rates from this proceeding, the amount of the monthly ECR revenue requirement collected through base rates will be adjusted to reflect the ECR project eliminations in the same manner that occurred following the ECR project elimination in Case No. 2012-00222.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 85

Responding Witness: Robert M. Conroy / William Steven Seelye

Q-85. Refer to the Conroy Testimony, page 22, lines 3–6.

a. Provide support for adding an evening winter peak time to Rates RTOD-Demand and RTOD-Energy.

b. Provide a bill comparison of the average customer's energy bill portion.

A-85.

a. See pages 21 through 25 of Mr. Seelye's direct testimony.

b. The following table is derived from information found in the filing requirements Tab 66 Schedule M-2.3-E.

	Average Annual Customer Energy Revenue at Current Rates	Average Annual Customer Energy Revenue at Proposed Rates	Percent Change
LGE RTOD-E On-Peak	$220.94	$276.08	25%
LGE RTOD-E Off-Peak	$686.48	$755.44	10%
LGE RTOD-E Total	$907.42	$1,031.52	14%
LGE RTOD-D	$0.00	$0.00	-

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 86

Responding Witness: Robert M. Conroy

Q-86. Refer to the Conroy Testimony, page 26, lines 4–8. Mr. Conroy states that under the proposed NMS-2, customer-generators who size their generating systems to align the generation with their own consumption will receive that same value for the energy consumed as if they were under Rider NMS-1. Provide support to this statement.

A-86. As long as a customer's consumption exceeds the customer's energy production at all times, the customer's value of energy will be the same under NMS-1 and NMS-2; namely, each kWh produced will offset a kWh the customer otherwise would have consumed and for which the customer would have paid the full retail rate. Only when the generation is greater than consumption does the value of energy differ between NMS-1 and NMS-2; excess generation offsets consumption in the same or future billing periods on a one-to-one kWh basis under NMS-1, whereas NMS-2 values excess generation at the SQF rate and provides a bill credit to the customer for that value.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 87

Responding Witness: Robert M. Conroy

Q-87. Refer to the Conroy Testimony, page 26. Explain whether LG&E considered allowing customers that take service under time-of-use rates to be compensated for production based on the time-differentiated rate set forth in Standard Rate Rider SQF.

A-87. For simplicity, the Company only considered compensation for energy fed back on the grid for net-metering customers at the non-time-differentiated rate under Rider SQF. The time periods under the time-differentiated rates for Rider SQF differ from the time periods used in the various time-of-use rate schedules.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 88

Responding Witness: Robert M. Conroy

Q-88. Refer to the Conroy Testimony, page 28, lines 11–18. Explain whether the Commission will still approve the Net Metering application.

A-88. Yes. As noted in the testimony, the Companies will continue to file any changes to the net metering application forms with the Commission under the administrative case concerning net metering guidelines. The existing application form removed from the tariff has not been modified from previous Commission approval.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 89

Responding Witness: Eileen L. Saunders

Q-89. Refer to the Conroy Testimony, page 30, lines 5–10, which discusses the revision to Rate PS to remove the mandatory requirement for a contract, thus allowing LG&E to require a contract for an initial term at their discretion. Explain how LG&E would decide whether or not to require a contract for an initial term to a prospective Rate PS customer.

A-89. The Business Service Center and/or Major Accounts team determines when a PS customer needs to sign an initial contract. Such contracts are required only if the customer's electric service requires additional facilities or other ancillary services, such as those under the excess facilities or redundant capacity riders. This contract functions to assist the Customer Services representative and the customer to see the whole picture in terms of all components of the customer's bill.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 90

Responding Witness: Eileen L. Saunders

Q-90. Refer to the Conroy Testimony, page 30, line 10. For the contracts for Rate PS, state at whose discretion initial term is assigned.

A-90. Customer Services, specifically the Business Service Center and/or Major Accounts team.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 91

Responding Witness: Robert M. Conroy

Q-91. Refer to the Conroy Testimony, page 33, lines 14–23 and page 34, lines 1–7.

a. Regarding the legacy customers in Rates GS and PS, confirm this does not remove all legacy customers.

b. As LG&E's proposed electric tariff has been suspended up to and including June 30, 2021, state the usage period that will be examined to determine whether legacy customers meet the applicable availability requirements of Rates GS and PS.

c. For those customers losing legacy status if LG&E's proposal in this case is approved, explain how often their 12-month average maximum load will be reviewed to determine their continued participation in Rate GS and PS.

d. Explain how customers will be notified that they are being moved to another rate schedule if they no longer qualify for their current rate schedule.

A-91.

a. Confirmed. This approach will not remove all legacy customers.

b. The Companies will use data for the 12 months ending January 31, 2020, to avoid the effects of COVID on customers' usage data.

c. The only customers losing their legacy status are those whose 12 month average demand matches the tariff requirements for the rate schedule they are currently under. Once these customers lose their legacy status they will fall under the Company's existing tariff review process performed for all non-residential customers annually in accordance with the CUSTOMER RATE ASSIGNMENT provisions in Sheet Nos 101.1 and 101.2.

d. No customers whose legacy rate differs from the existing tariff requirements will have their rate changed through this proposed process. See the response to part c. Notification of a change in rate schedule will follow the CUSTOMER RATE ASSIGNMENT provisions in Sheet Nos 101.1 and 101.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 92

Responding Witness: Robert M. Conroy

Q-92. Refer to the Conroy Testimony, page 34, lines 18–20, which discusses the additional LED fixture offerings under Rate LS. Also refer to Tab 4 of the Application, P.S.C. Electric No. 13, Original Sheet No. 35.1. Explain the discrepancy between the testimony and the proposed tariff regarding which additional LED offerings LG&E is proposing through Rate LS.

A-92. The testimony inadvertently stated that "the Companies will have two additional LED fixture offerings under Rate LS: Victorian (KU only) and London (both Companies)." The testimony should have stated that "the Companies will have two additional LED fixture offerings under Rate LS: Victorian (both Companies) and London (LG&E only)."

LG&E is introducing two additional LED fixture offerings under Rate LS, the Victorian and London LED fixtures, consistent with Tab 4 of the Application, P.S.C. Electric No. 13, Original Sheet No. 35.1. LG&E's Victorian and London HPS fixtures are moving to Rate RLS.

KU is introducing one additional LED fixture offering under Rate LS, the Victorian LED fixture, consistent with Tab 4 of the Application, P.S.C. No. 20, Original Sheet No. 35.1. KU's Victorian HPS fixtures are moving to Rate RLS. Due to historic naming conventions, the KU Victorian fixture is equivalent to the LG&E London fixture.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 93

Responding Witness: John K. Wolfe

Q-93. Refer to the Conroy Testimony, page 35, lines 5–9, which discusses removal costs being incorporated into Restricted Lighting Service Tariff and the circumstances under which a Rate RLS customer who requests removal of an existing Rate RLS lighting system may be required to pay a conversion fee. Explain the circumstances under which a Rate RLS customer who requests removal of a Rate RLS lighting system and subsequently requests installation of an LED replacement would not be required to pay the conversion fee.

A-93. This provision is intended to prevent customers from requesting removal of an RLS fixture and subsequently requesting installation of an LS fixture for the sole purpose of avoiding the conversion fee. On the other hand, the company does not wish to punish customers who in good faith request a removal of an RLS fixture and then subsequently determine they need a new LS fixture at that location. This provision will be applied on a case by case basis by company personnel that work with these customers. An example of when the conversion fee would not be required is if a customer with an overhead fed RLS fixture requests removal because their business is closing indefinitely due to financial hardships. Company's practice will be to remove that fixture. If two years, later that same customer request a new fixture at that business, only LS fixtures will be available and that customer would not be charged a conversion fee.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 94

Responding Witness: John K. Wolfe

Q-94. Refer to the Conroy Testimony, page 35, lines 10–15, which discusses when a Lighting Service Tariff customer must enter into a contract. Explain the reasoning for the additional circumstances under which a contract will be required.

A-94. The goal of this provision is to protect the company in these scenarios where it is making a sizeable investment in new Lighting infrastructure and the customer is making a corresponding financial obligation to the Company. The contract requires the customer to pay the balance of the 5 year contract in the event of early termination and provides an incentive for the customer to maintain its lighting service through the Company long-term. The contract will also help better inform the customer making this commitment of the terms and conditions accompanying that installation. The existing language only requires a contract when additional facilities are required to serve the customer, a requirement that, in part, exists to protect the Company's investment and, in part, to ensure the customer understands what they are agreeing to with the excess facilities charges. It only makes sense to extend this requirement in other scenarios when both parties have a significant financial interest. The Company is not pursuing a contract for every lighting installation due to concerns with operationalizing that requirement and overburdening staff, and to not place unnecessary delays on a straightforward transaction with the customer.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 95

Responding Witness: John K. Wolfe

Q-95. Refer to the Conroy Testimony, page 36, lines 3–6, which discusses the change in the High Volume Application definition in Rate PSA. Explain the extent of additional work required to review wireless attachments when applications are made for more than 30 wireless attachments in a 30-day period.

A-95. The process for reviewing wireless attachments is more time-consuming than wireline applications and goes beyond a review to confirm that safe clearances are maintained between facilities on the pole. The review begins with an assessment of whether an antenna can be safely attached to the targeted pole at all, or if there are electric facilities on the pole that will preclude attachment. It requires checking that the proposed installation method matches the Company's standards, including the meter type and placement, the type and size of conduit and wire to be used, and the type and placement of the required disconnect switch and radiofrequency emissions signage.

If applications are made for more than 30 wireless attachments in a 30-day period, and made by the multiple attaching entities that are currently, the Company will find it difficult to complete all of the reviews—for both wireline and wireless applications—within the time period contained in Rate PSA.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information Dated January 8, 2021

Case No. 2020-00350

Question No. 96

Responding Witness: Robert M. Conroy

Q-96. Refer to the Conroy Testimony, page 37, lines 8–18, which discusses changes to the rates in Rate EVSE and Electric Vehicle Supply Equipment Rider (Rider EVSE-R). Also, refer to Tab 4 of the Application, P.S.C. Electric No. 13, Original Sheet No. 41 and P.S.C. No. 13, Original Sheet No. 75. The testimony indicates that Rate EVSE and EVSE-R are being revised to include a rate for the single and dual charger versions of the Level 2 charging stations; however, the only changes being made to the rate section of those two schedules are text changes and the addition of a non-networked charger rate. Explain the discrepancy between the testimony and the proposed tariff.

A-96. The Company inadvertently stated in testimony that Rate EVSE and EVSE-R are being revised to include a rate for the single and dual charger versions of the non-networked Clipper Creek HCS-40 charging station. Only a single version of this unit is to be offered. In this same section, the Company also incorrectly categorized this station as a Level 3 charging station. All existing and proposed EVSE and EVSE-R offerings are Level 2 charging stations. Mr. Seelye's testimony explaining Level 3 charging station rates referenced in this section is related to the rates developed for Rate EVC-Fast.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 97

Responding Witness: Eileen L. Saunders

Q-97. Refer to the Conroy Testimony, page 40, lines 10–14, which discusses the situations under which a customer would and would not be charged the initial set-up fee for opting out of AMI. Explain how much notice a customer will receive to elect to opt-out before AMI meter installation at the customer's premises.

A-97. The Companies intend to follow the customer communication schedule found at the top of page 10 of Exhibit ELS-2. Communications in the local area will start roughly six weeks prior to the scheduled meter exchange. There are successive direct customer communications 4 weeks, 2 weeks, and the week of the meter installation. These direct customer communications will include opt-out information to ensure customers have proper notice and adequate time to elect to opt-out. Additionally, customers can proactively elect to opt-out at any time including directly with the meter installation technician on the day of their installation.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 98

Responding Witness: Robert M. Conroy / Eileen L. Saunders

Q-98. Refer to the Conroy Testimony, page 40, line 21 through page 41, lines 3, which states that LG&E may require a customer to opt out if the customer has a history of particularly dangerous or repeated meter tampering and also states that LG&E may refuse to allow a customer to opt out if the customer has a history of tampering. Explain how these two statements are not contradictory and how LG&E will decide whether or not a customer with a history of tampering will be allowed to opt out.

A-98. In the first statement, the Company may require a customer to opt out if the customer has a history of particularly dangerous or repeated meter tampering. An example of this scenario would be a customer splicing additional service drops, e.g. for a previously unserved garage, from their home's service drop. Such cases, though rare, can present dangerous hazards to the public and can be difficult to detect remotely via AMI. Therefore, it may become necessary for the Company to regularly visit those customers' premises to ensure safe, reliable, and accurate services, and it is appropriate for the customers who necessitate such visits to pay their cost through AMI Opt-Out charges.

In the second statement, the Company is establishing that there are also safety, reliability, and accuracy reasons to deny a customer request to be opted out. Conroy Testimony, page 41, lines 4 through 6 go on to identify such scenarios whereby a customer may have opted out and the Company must opt the customer back into the AMI offering.

The Company notes that both statements are similar language to what is included in Duke Energy Kentucky's tariffs and were approved in Case No. 2017-00321 and Case No. 2019-00271.[24] The Company will use the frequency and severity of the events described in Conroy Testimony, page 41, lines 4 through 6, as criteria to determine each course of action. The tariff states that after a year a customer

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[24] See https://www.duke-energy.com/ /media/pdfs/rates/ky/sheetno91reconchg.pdf?la=en and https://www.duke-energy.com/ /media/pdfs/for-your-home/rates/electric-ky/sheet-no-74-rider-amo-ky-e.pdf?la=en

request to opt out would be granted should there not be any evidence of additional events within that year.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 99

Responding Witness: Eileen L. Saunders

Q-99. Refer to the Conroy Testimony, page 40, lines 21–23 and page 41, lines 1–6.

a. Provide the annual number of tampering and repeated tampering issues LG&E annually experiences for the past three years.

b. Provide the decision metric that determines whether LG&E refuses to allow a customer to opt out of the proposed AMI meter due to a history of tampering.

A-99.

a.

Year	Accounts with Tampering	Accounts with Tampering More than Once
2018	4,146	628
2019	3,444	511
2020	1,435	162

b. See the response to Question No. 98.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 100

Responding Witness: Robert M. Conroy

Q-100. Refer to the Conroy Testimony, page 44, lines 8–9, which discusses LG&E's proposal to limit their liability for damages resulting from their meter pulse data or the service in general.

a. Generally, explain why it would be appropriate to include language shielding a regulated utility from potential liability in a tariff.

b. Specifically, explain why LG&E should limit their liability in relation to meter pulse service, include in this explanation a discussion LG&E's objective for the inclusion of liability limiting language related to meter pulse data or service.

A-100.

a. Liability-limitation clauses are common in many contracts, including LG&E's standard contract for meter pulse service. A utility's tariff is effectively its standing contract with all who would do business with it, with the notable difference that it is a contract that is governed by the relevant administrative agency and can change only with that agency's approval. Not to have liability-limitation provisions in a utility's tariff could lead to ruinous liability for the utility, which is bound by law to serve all who come; regulated utilities do not get to choose their customers, but rather are obligated to serve all who comply with the terms of the approved tariff. Unlimited liability would pose a grave risk not only to the utility but also its customers, whose service and rates could ultimately be affected by such liability.

Moreover, the Commission has approved liability-limitation provisions in LG&E's and KU's tariffs for decades.[25] The Commission has approved liability-limitation provisions in other utilities' tariffs, as well.[26]

b. Liability limitation is ordinarily a term included in LG&E's contracts for meter pulse service. Including the liability limitation provision in the tariff helps ensure customers are aware of the provision before seeking the service from LG&E, and it reduces the length of the meter pulse contract.

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[25] *See, e.g.,* Louisville Gas and Electric Company, P.S.C. of Ky. Electric No. 5, Original Sheet No. 44 (eff. June 29, 1992; refiled Feb. 21, 2000); Louisville Gas and Electric Company, P.S.C. of Ky. Gas No. 5, Original Sheet No. 30 (eff. June 29, 1992; refiled Oct. 16, 2000); Kentucky Utilities Company, P.S.C. No. 12, Original Sheet No. 245-A (eff. Apr. 18, 1994; refiled Feb. 21, 2000).

[26] *See, e.g., Duke Energy Kentucky, Inc., Ky. P.S.C. Electric No. 2, Second Revised Sheet No. 21, Ninth Revised Sheet No. 60, Ninth Revised Sheet No. 66, Ninth Revised Sheet No. 68, Ninth Revised Sheet No. 69, Original Sheet No. 87, and Third Revised Sheet No. 92; Kentucky Power Company, P.S.C. Ky. No. 11, First Revised Sheet No. 2-6, Original Sheet No. 2-15, Original Sheet No. 3-1, Original Sheet No. 16-4, Original Sheet No. 32-4.*

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 101

Responding Witness: William Steven Seelye

Q-101. Refer to the Conroy Testimony, page 45, lines 2–7. Provide support for the decrease in the Meter Pulse Charge from $24 to $21.

A-101. The cost support for the Meter Pulse Charge is shown on page 10 of Exhibit WSS-19 of the Direct Testimony of William Steven Seelye filed on November 25, 2020, in this proceeding.

The primary reason for the proposed decrease in the monthly charge is a reduction in the total cost of the equipment used to provide the service. In LG&E's previous rate case (Case No. 2018-00295), the equipment cost – including the pulse relay, pulse initiator board, and relay enclosure – was estimated to be $400 per installation. LG&E now estimates equipment cost to be $305 per installation.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 102

Responding Witness: Robert M. Conroy

Q-102. Refer to the Conroy Testimony, page 45, lines 13–23.

a. Explain why LG&E is proposing to change the language so that a legal holiday that falls on a weekday will be considered a weekday for purposes of determining an on-peak period.

b. Explain why LG&E is proposing to change the language from actual variable fuel expenses to actual fuel expenses, excluding those that are fixed and non-variable.

A-102.

a. The change in classification of a legal holiday that falls on a weekday within the SQF tariff to a weekday aligns the application for billing with the Company's other time-of-day tariff offerings.

b. Currently, due to FERC Uniform System of Accounts requirements, certain fixed and non-variable costs, such as long-term lease contracts for rail cars used to transport coal, are consumed (that is, expensed) based on unit performance during the month. Therefore, these costs are considered to be variable for purposes of determining avoided energy costs pursuant to the LQF Tariff when in reality, they are fixed. The purpose of the proposed change in language is to allow the Company to exclude fuel related costs that are fixed and non-variable when originally booked to the fuel inventory account from the determination of avoided energy costs since these costs are not avoidable by the Company.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 103

Responding Witness: Robert M. Conroy

Q-103. Refer to the Conroy Testimony, page 45, lines 16–23, which discusses a change to the definition of hourly avoided energy cost. Explain if this change is strictly for clarification purposes or if this represents a change in how LG&E determines the hourly avoided energy cost.

A-103. As discussed in the response to Question No. 102, part b, this would represent a change in how the Company determines the hourly avoided energy cost because the non-avoidable fixed and nonvariable fuel costs would no longer be included in the credit provided to LQF customers.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information Dated January 8, 2021

Case No. 2020-00350

Question No. 104

Responding Witness: Robert M. Conroy

Q-104 Refer to the Conroy Testimony, page 46, lines 15–17, which states that Excess Facilities customers who request the facilities be removed are responsible of the actual cost of removing the facilities they ask LG&E to install. Explain how removal costs are currently recovered from Excess Facilities customers.

A-104. The Company's current tariff and customer contracts are silent regarding removal costs and removal costs were not included in the determination of the excess facility rate. As such on the rare event a customer requests to have these facilities removed, the Company has incurred the cost. This proposed change will allow for the appropriate recovery of the cost incurred from the Excess Facilities customer.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 105

Responding Witness: Robert M. Conroy / Eileen L. Saunders

Q-105. Refer to the Conroy Testimony, page 49, lines 6–22, which discusses LG&E's proposal regarding late payment charges for nonresidential customers.

a. For the past two calendar years, provide the number and dollar amounts of residential late payment charges that have been waived by year under the provision in the residential rate schedules allowing customers to request that one late payment charge per year be waived.

b. For the past two calendar years, provide the number of customers, by type of customer and by year, that have paid late more than once per year.

c. For the past two calendar years, provide the on-time pay percentage by type of customer and by year.

d. Explain how customers are made aware that they have the option to have one late payment charge waived per 12-month period as long as they remain in good standing.

e. Explain why LG&E does not default waive the late payment charge if the customer has been in good standing for the requisite period.

A-105.

a. See attached.

b. See attached.

c. See attached.

d. If a customer contacts the Company inquiring about a late payment charge (LPC) and has been in good standing for the past 11 months, the representative will waive the LPC upon the request of the customer.

e. The late payment charge is not waived automatically because it is felt the automatic forgiveness would likely go unnoticed. Being able to waive a late payment charge for a customer when they call creates a positive customer experience.

Louisville Gas and Electric Company
January 2019 through December 2020

Residential One Time Only Waived Late Payment Charges

Year	Annually	January	February	March	April	May	June	July	August	September	October	November	December
2019	$ 1,751	-	-	-	$ 30	$ 122	$ 139	$ 186	$ 338	$ 281	$ 252	$ 213	$ 189
2020	$ 719	$ 254	$ 279	$ 186	-	-	-	-	-	-	-	-	-

Count of One Time Only Residential Waived Late Payment Charges

Year	Annually	January	February	March	April	May	June	July	August	September	October	November	December
2019	342	-	-	-	6	27	30	40	57	48	45	44	45
2020	124	43	51	30	-	-	-	-	-	-	-	-	-

*Moratorium on waived late payment charges March 16, 2020 through December 31, 2020

Louisville Gas and Electric Company
January 2019 through December 2020

Customers with More Than One Late Payment Charge

Year	Annually	Commercial	Industrial	Public Authority	Residential	Street Lights	Transport
2019	127,750	7,222	103	91	120,275	38	21
2020	127,120	8,409	114	71	118,467	41	18

Louisville Gas and Electric Company
January 2019 through December 2020

Percentage of Customers Paid on Time

Year	Commercial	Industrial	Public Authority	Residential	Street Lights	Transport
2019	93%	93%	99%	84%	98%	91%
2020	92%	93%	100%	85%	98%	91%

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 106

Responding Witness: Robert M. Conroy

Q-106. Refer to the Conroy Testimony, page 50, lines 6–9, which explains that the definition of Single Family Unit is being revised. Explain whether separately metered vacation rental, boat slips, or campers are currently eligible for residential service. If so, explain the reason for the change.

A-106. Separately metered vacation rental, boat slips, or campers are not currently eligible for residential service. Inclusion of this language is to eliminate customer confusion.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 107

Responding Witness: Robert M. Conroy

Q-107. Refer to the Conroy Testimony, page 52 line 1 through page 53, line 2, which discusses revisions to the As-Available Gas Service Tariff (Rate AAGS). Explain the circumstances under which LG&E would discontinue service to one or more, but not all, customers served under Rate AAGS and explain how LG&E would determine which customers would have their service discontinued.

A-107. Rate Schedule AAGS (As-Available Gas Service) is an interruptible gas sales service that allows LG&E to interrupt gas deliveries to customers served under the rate schedule. Such interruption allows LG&E to continue to provide gas service "without impairment of service to customers served under other higher priority rate schedules."

LG&E currently provides gas sales service to three interruptible customers pursuant to Rate AAGS. LG&E is proposing to clarify Rate Schedule AAGS so that an individual customer may be required to interrupt without interrupting all interruptible customers when the interruption of an individual customer will alleviate the issue.

In instances during which the need for interruption is the result of a system-wide phenomenon (e.g., extreme cold weather), all customers may be interrupted. In instances where there is a local phenomenon (e.g., such as pipeline outage or some other capacity constraint), only an individual customer in that locality may be required to interrupt, thus alleviating the need to interrupt customers whose interruption would not meaningfully address the local phenomenon.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 108

Responding Witness: Robert M. Conroy

Q-108. Refer to the Conroy Testimony, page 53, lines 4–7, which discusses the revisions to the Firm Transportation Service Tariff (Rate FT) regarding gas generators whose generation facilities are installed and operating 90 days after January 1, 2021. Explain the reasoning for this change.

A-108. LG&E's proposed tariff language is designed to improve the accuracy associated with the measurement of gas used in standby gas-fired generation applications by establishing separate points of delivery for gas provided pursuant to Rate FT and gas provided for standby gas-fired generator applications. Improved measurement accuracy benefits all customers.

Proper gas meter selection is determined by customer load requirements. When selecting a meter, specific attention must be given to a potential gas meter's rangeability. For example, a meter that is sized for a large Rate FT industrial customer's gas load will not accurately measure the considerably lower use of a standby generator when the customer's regular production equipment is off during a power outage and the generator may be on. Additionally, a meter sized for a smaller Rate FT customer who has a large gas generator, would not accurately measure the customer's load when the large generator is not in operation. The requirement to exclude generators from gas service under Rate FT will help ensure gas meter accuracy for Rate FT customers.

The proposed change is consistent with LG&E's current practice for smaller commercial and industrial gas fired standby generator installations. The proposed language brings clarity and transparency to LG&E's Gas Tariff. Customers with existing installations will not be subject to modification as described in the proposed tariff.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 109

Responding Witness: Robert M. Conroy

Q-109. Refer to the Conroy Testimony, page 53, lines 7–9, which discusses the revision to Rate FT, Variations in MMBTU Content section, regarding the price to cash out such variations. Explain the reasoning for the change and explain if this changes how LG&E currently determines the cash-out price.

A-109. The methodology used to cash out over- or under-deliveries arising from variations in MMBtu content from a prior month is identical in Rate FT, Rider PS-TS-2, and Rate LGDS.

The additional language is intended to bring clarity to the price used for the cash-out of such volumes (which are typically de minimis) and increase the transparency of how the respective tariff operates.

There is no change to the methodology currently used by LG&E to determine the cash-out price for Rate FT, Rider PS-TS-2, and Rate LGDS.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 110

Responding Witness: Robert M. Conroy

Q-110. Refer to the Conroy Testimony, page 53, lines 11–12, which discusses the revision to the Local Gas Delivery Service Tariff, Variations in MMBTU Content section, regarding the price to cash out such variations. Explain the reasoning for the change and explain if this changes how LG&E currently determines the cash-out price.

A-110. See the response to Question No. 109.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 111

Responding Witness: Robert M. Conroy

Q-111. Refer to the Conroy Testimony, page 53, lines 16–19, which discusses the revision to the Pooling Service Rider TS-2, Variations in MMBTU Content section, regarding the price to cash out such variations. Explain the reasoning for the change and explain if this changes how LG&E currently determines the cash-out price.

A-111. See the response to Question No. 109.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 112

Responding Witness: Robert M. Conroy

Q-112. Refer to the Conroy Testimony, page 54, lines 2–4, which discusses LG&E's proposal to include a disclaimer of liability and responsibility regarding the fitness of any gas provided under the Natural Gas Vehicle Service tariff (Rate NGV) as a fuel in vehicular internal combustion engines.

a. Generally, explain why it would be appropriate to include language shielding a regulated gas utility from potential liability under a tariffed rate schedule such as Rate NGV when the sole purpose of the rate schedule is to provide natural gas for use as a fuel in vehicular internal combustion engines.

b. Specifically, explain why LG&E should limit its responsibility for gas provided under Rate NGV, include in this explanation a discussion of LG&E's objective for the inclusion of liability limiting language related to the fitness of any gas provided under the Rate NGV tariff.

A-112.

a. The specific language which LG&E is proposing to add to Rider NGV on Sheet 63.1 of its natural gas tariff is as follows:

> Company does not warrant the fitness of any gas delivered hereunder for use as a fuel in vehicular internal combustion engines. It shall be the sole responsibility of Customer, and at its cost, to monitor the fitness of such gas and to take any corrective action(s) as may be necessary.

LG&E's gas quality standards are set forth in the "Heating Value" section of its Gas Tariff on Sheet No. 99. LG&E represents that the gas it is distributing meets those standards. Largely, the quality of the natural gas is within the control of the interstate pipeline(s) delivering that natural gas to LG&E. Pipeline quality gas is expected to meet the conventional needs of residential, commercial, and industrial customers.

However, customers served under Rider NGV compress the natural gas delivered by LG&E when used as vehicular fuel. Such compression may cause constituents normally found suspended in the natural gas stream to become liquified in (or "drop out" of) the natural gas stream. These normally occurring constituents, once liquified, may not be compatible with the fuel specifications of the vehicular internal combustion engines using natural gas as a fuel.

The customer taking service under Rider NGV is familiar with the fuel specifications of its vehicular internal combustion engines which are using natural gas as a fuel. LG&E is unable to determine if the gas delivered to the customer will be within the operating tolerance(s) of that equipment once compressed. It is up to the customer to make that determination and to take any corrective action(s) as may be necessary.

Therefore, it is wholly appropriate that LG&E's liability in such instances be limited as proposed in its tariff language.

b. See the response to (a) above.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 113

Responding Witness: Robert M. Conroy

Q-113. Refer to the Conroy Testimony, page 54, lines 6–8, which discusses LG&E's proposed revisions to its Gas Supply Clause (GSC) to allow for recovery through the GSC of the costs of vaporized liquefied petroleum gas and air and liquefied natural gas.

a. Explain why LG&E is proposing this addition to its GSC tariff.

b. Explain how often vaporized liquefied petroleum gas and air and liquefied natural gas have been used and why they have been used to supplement the gas supply.

c. For the test year and each of the five preceding years, provide the costs for vaporized liquefied petroleum gas and air and liquefied natural gas.

A-113.

a. LG&E is currently permitted to supplement its supplies of natural gas with a mixture of vaporized liquified petroleum gas and air as set forth in LG&E's current Gas Tariff in the "Heating Value" section found in LG&E's Gas Tariff on Sheet No. 99.

LG&E is proposing to clarify that it may also use liquified natural gas to supplement its supplies of natural gas received from interstate pipelines. Such liquified natural gas could be used in addition to or instead of petroleum gas and air as a potentially more effective means of supplementing pipeline supplies of natural gas.

The changes proposed to LG&E's Gas Supply Clause are intended to clarify LG&E's ability to recover the associated costs through its Gas Supply Clause.

b. No such supplements to gas supply have previously occurred.

c. No such costs are included in the test year nor have costs previously been incurred.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 114

Responding Witness: Robert M. Conroy

Q-114. Refer to the Conroy Testimony, RMC-2 and RMC-3. For the amount of the unprotected excess ADIT, confirm that this is the balance as of July 1, 2021.

A-114. Confirmed. The amount of non-plant unprotected excess ADIT included in Exhibit RMC-2 and Exhibit RMC-3 represents the balance as of July 1, 2021.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information Dated January 8, 2021

Case No. 2020-00350

Question No. 115

Responding Witness: Eileen L. Saunders / William Steven Seelye

Q-115. Refer to the Direct Testimony of William Steven Seelye (Seelye Testimony), page 11, lines 16–18. Mr. Seelye indicates the importance of the informational purpose of the separation of the energy charge between the variable energy charge and the infrastructure energy.

a. Provide the number of times since the last base rate case where a customer has called LG&E to inquire about the energy charge components.

b. Provide any customer service representative dialog scripted for questions regarding the energy and infrastructure charges.

A-115.

a. The Company does not maintain the requested data. The Company endeavors to make meaningful information available to customers and stakeholders concerning the types of costs recovered through rates regardless of how many customers have actually inquired about the energy cost components of rates.

b. There is no customer service representative dialog scripted for questions regarding the energy and infrastructure charges. See the response to part a.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 116

Responding Witness: William Steven Seelye

Q-116. Refer to the Seelye Testimony, page 14, Table 4. Provide a similar table representing the last five base rate cases

A-116. Below is a comparison of the percentage of costs broken down by component (customer cost, demand cost, and energy cost) and the percentage of cost recovery through the proposed rate components (customer charge and energy charge) as filed in the current case and the preceding five LG&E base rate cases.

CASE NO. 2020-00350

Component	Percentage of Cost	Rate Design
Customer	19.74%	14.8%
Demand	53.18%	0.0%
Energy	27.08%	85.2%

CASE NO. 2018-00295

Component	Percentage of Cost	Rate Design
Customer	22.2%	14.1%
Demand	45.6%	0.0%
Energy	32.2%	85.9%

CASE NO. 2016-00371

Component	Percentage of Cost	Rate Design
Customer	22.9%	11.5%
Demand	40.6%	0.0%
Energy	36.5%	88.5%

CASE NO. 2014-00372

Component	Percentage of Cost	Rate Design
Customer	21.28%	11.83%
Demand	35.35%	0.0%
Energy	43.37%	88.17%

CASE NO. 2012-00222

Component	Percentage of Cost	Rate Design
Customer	20.62%	9.67%
Demand	33.48%	0.0%
Energy	45.90%	90.33%

CASE NO. 2010-00549

Component	Percentage of Cost	Rate Design
Customer	20.73%	6.56%
Demand	29.47%	0.0%
Energy	49.80%	93.44%

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 117

Responding Witness: William Steven Seelye

Q-117. Refer to the Seelye Testimony, page 24, lines 1–2. Provide LG&E's electric winter peak and date for the past ten years.

A-117.

Date	LG&E Winter Peak (MW)
01/12/2011	1,811
03/21/2012	1,812
01/22/2013	1,784
01/06/2014	2,096
01/08/2015	1,976
01/18/2016	1,821
01/06/2017	1,791
01/02/2018	1,909
01/30/2019	1,934
02/14/2020	1,703

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 118

Responding Witness: William Steven Seelye

Q-118. Refer to the Seelye Testimony, page 25, lines 1–9. Explain why LG&E is proposing to increase the off-peak Energy Charge and decrease the on-peak energy charge for Rate RTOD-Energy.

A-118. The decrease in the on-peak charge for Rate RTOD-Energy is the result of adding four hours to the peak period during the Winter Months. As explained on page 22 of the Direct Testimony of William Steven Seelye filed on November 25, 2020, in this proceeding, the Companies are proposing to add four evening hours (i.e., the hours from 6 PM to 10 PM) to the peak period during the Winter Months. This results in spreading peak period costs under Rate RTOD-Energy over a larger number of peak period kWh, thus resulting in a net decrease in the peak period charge, even after considering the proposed increase to peak period revenue. The increase in the off-peak charge for Rate RTOD-Energy reflects the impact of increasing the overall revenue for the rate class.

As shown on page 3 of Schedule M-2.3-E for LG&E, adding four hours to the winter peak period increases the peak period kWh for the test year from 176,683 kWh to 252,254 kWh. Even though the Company is proposing to increase the peak period infrastructure charge revenue from $30,570 to $37,091, the charge is lower ($0.17302 per kWh currently versus $0.14704 per kWh as proposed) because the peak period revenue is spread over a larger number of kWh. In other words, the impact of increasing in the peak period kWh more than offsets the increase in peak period revenue.

See also page 25, lines 7-9, of Mr. Seelye's direct testimony.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 119

Responding Witness: Eileen L. Saunders

Q-119. Refer to the Seelye Testimony, page27, lines 4–5.

a. Provide the amount of LG&E General Service (GS) customers who currently have an AMI meter.

b. Explain whether any GS customers have inquired about time of day rates.

A-119.

a. There are currently 251 LG&E General Service (GS) customers who have an AMI meter as part of the Advanced Metering Systems Customer Service Offering that would be eligible to take service under Rate GTOD-Energy or GTOD-Demand.

b. The Company does not maintain the requested data. However, the Company is proposing this optional rate to give general service customers the option of a time of day rate if they choose to do so.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information Dated January 8, 2021

Case No. 2020-00350

Question No. 120

Responding Witness: Eileen L. Saunders

Q-120. Refer to the Seelye Testimony, page 33, lines 3–10. The outdoor sports lighting service (Rate OSL) can have up to 20 participants, but LG&E only have one. Explain if LG&E has proactively discussed this rate option with local schools and parks.

A-120. Yes, the Company has proactively discussed this rate option with local schools and parks.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information Dated January 8, 2021

Case No. 2020-00350

Question No. 121

Responding Witness: William Steven Seelye

Q-121. Refer to the Seelye Testimony, page 34, lines 4–13. Explain why LG&E is proposing to decrease the revenue from Rate OLS by approximately 10 percent.

A-121. LG&E is proposing a 10 percent decrease for Rate OSL because of the high rate of return for the rate class as determined by the Company's cost of service studies. Based on the LOLP cost of service study, the rate of return for Rate OSL is 89.10%. Based on the 12 CP and 6 CP cost of service studies, the rate of return for Rate OSL is 92.28% and 92.63%, respectively. The rate of return for Rate OSL is the highest of any rate class. See Exhibit WSS-22, page 2 of 2.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 122

Responding Witness: William Steven Seelye

Q-122. Refer to the Seelye Testimony, page 47, line 12. Provide the subsidy that LG&E residential customers are paying to current net metering customers.

A-122. LG&E's residential customers (non-net metering residential customers) are currently paying two types of subsidies to net metering customers.

(1) With the first type of subsidy, residential and other non-net metering customers are currently paying subsidies to net metering customers because of the overcompensation provided by the Companies for the energy that net metering customers supply to the grid. If a net metering customer generates more power than the customer uses during the month, the customer is currently compensated at a rate equal to the energy charge in the customer's underlying rate.

If the customer is a residential customer served by LG&E, the customer is currently compensated at an energy rate of approximately $0.10482 per kWh, including cost trackers. However, this is several times the cost for which LG&E could otherwise generate the energy itself or purchase the energy from a third party in the wholesale power market. Based on its avoided cost-based rate set forth in the Small Capacity Cogeneration and Small Power Production Qualifying Facilities (Rate SQF), LG&E could generate or procure the energy at a cost of only $0.02173 per kWh. Therefore, LG&E is currently overcompensating net metering customers $0.08309 per kWh for the energy that they supply to the grid, which is a cost other customers ultimately bear. For the 12 months ended November 30, 2020, LG&E residential net metering customers supplied 1,789,238 kWh to the grid at an average credit of $0.10482, and thereby received billing credits of $187,548. But LG&E could have generated the power for only $38,880 (1,789,238 kWh x $0.02173 = $38,880). Therefore, LG&E overcompensated its net metering customers by $148,668 ($187,548 - $38,880 = $148,668).

Although the question does not ask about subsidies received by net metering customer served under Rate GS, the amount is $31,753. The subsidies received by net metering customers in other rate classes are negligible.

Therefore, the total subsidies provided to LG&E's net metering customers served under Rates RS and GS by overcompensating these customers for the power they put on the grid are $180,421.

With the introduction of NMS-2, this first subsidy will be eliminated for all new net metering customers. While these subsidies are relatively small in relation to LG&E's total revenue, they would be expected to increase significantly without the introduction of NMS-2. In the past three years, the amount of net metering generation nameplate capacity has almost tripled on the LG&E system (from 1,820.8 kW in 2017 to 4,871.9 kW as of November 2020). LG&E is currently experiencing a 39% growth in the amount of net metering capacity on its system. Under KRS 278.466, net metering capacity is capped at 1% of LG&E's peak load during a calendar year. If this cap is reached on LG&E's system, then this first subsidy would increase to over $1.0 million. If the current rate of growth in distributed generation nameplate capacity on LG&E's system were to continue to increase at the current rate, the 1% cap would be reached in approximately 6 years. The large increase in the past few years illustrates how quickly costs can be shifted from one group of customers to another without regard to the underlying cost of service and the associated subsidies.

(2) With the second type of subsidy, residential customers are also currently paying subsidies due to the inability of a two-part rate (consisting of only a customer charge and energy charge) to reflect the actual cost of providing service to net metering customers. As explained in Mr. Seelye's direct testimony, net metering customers reduce the amount of energy that they purchase without typically reducing the maximum demands they place on the system. With a two-part rate consisting of only a customer charge and an energy charge, a net metering customer will pay lower demand costs recovered through the energy charge even though the demand costs incurred to serve a net metering customer are not typically lower than for a non-net metering customer. This second type of subsidy is addressed on pages 46-64 of Mr. Seelye's direct testimony.

LG&E estimates that residential net metering customers are currently receiving $95,175 in annual subsidies from this second type of subsidy, which again is a subsidy other customers ultimately pay. (It should be noted that this estimate is based on a limited amount load data that LG&E has for residential net metering customers. The load data used to develop these estimates are not based on a statistically valid sample, particularly considering the large variance in the usage patterns for net metering customers.)

Louisville Gas and Electric Company

Annual Fixed Demand Related Costs to Service Residential Net Metering Customer	$	776.18
Average kWh of Net Metering Customer		8,461.67
Proposed Infrastructure Charge	$	0.0724
Revenue Received per Net Metering Customer		612.37
Cost Subsidy Receive by Net Metering Customers	$	163.81
Number of Net Metering Customers		581
Annual Subsidy from Lower Residential Net Metering Customer Load Factor	$	95,175

As explained in Mr. Seelye's direct testimony, LG&E is not proposing to address this second subsidy at this time but plans to continue to study the issue in the future. However, LG&E expects these subsidies to increase as more customers install solar panels and possibly other distributed generation facilities. If the 1% cap on net generation capacity is reached on LG&E's system, then this second subsidy would increase to over $500,000 annually. As noted previously, if the current rate of growth in distributed generation nameplate capacity on LG&E's system were to continue to increase at the current rate, the 1% cap would be reached in approximately 6 years. This again illustrates how quickly costs can be shifted from one group of customers to another without regard to the underlying cost of service and the associated subsidies.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 123

Responding Witness: William Steven Seelye

Q-123. Refer to the Seelye Testimony, page 47.

a. Explain whether a phased approach to implementing LG&E's preferred net metering rate design would discourage investment in distributed generation in the interim, given that customers taking service under Tariff NMS-2 would risk the change in rate design, at an uncertain point in the future, affecting the economic analysis of the investment.

b. Explain whether meter upgrades would be necessary to provide four-part rates for Tariff NMS-2.

A-123.

a. By "preferred net metering rate design", it is assumed that the question is referring to the implementation of a four-part rate schedule as discussed on pages 46-64 of Mr. Seelye's testimony.

The Companies do not believe that phasing in a four-part rate will discourage investment in distributed generation. It should be clear to customers, and to intervenors that represent net-metering or solar generation customers, that the Companies will continue to investigate changes to their rate designs that more accurately reflect the cost of serving customers. While a four-part rate consisting of a Basic Service Charge, Energy Charge, Peak Demand Charge, and Base Demand Charge would more accurately reflect the cost providing service to net metering customers, the Companies have made no decision if or when they will implement such a rate design.

It should also be noted that utilities in other jurisdictions are taking a gradual approach to implementing three- and four-part rate designs for net-metering and non-net-metering customers. For example, some utilities are introducing three- and four-part rates that include demand charges that are lower than fully cost-based demand charges. Yet, other utilities are choosing to implement fully cost-based three- and four-part rate designs for net-metering and non-net-metering customers. KU and LG&E plan to continue to study the practicability of implementing demand rates for residential net-metering and other customers.

b. Upon implementation of the Company's Advanced Metering Infrastructure ("AMI") program, additional meter upgrades would not be required to implement four-part rates as described in Mr. Seelye's direct testimony.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 124

Responding Witness: Robert M. Conroy

Q-124. Refer to the Seelye Testimony, page 65, lines 1–3, which discusses LG&E's commitment in Case No. 2015-00355 that Level 2 charging service would not result in increased charges to the Companies' customers. Indicate whether LG&E is willing to make that same commitment in regards to the Level 3 charging service proposed in the instant matter. If not, explain why not.

A-124. LG&E is not making such a commitment. LG&E's deployment of Level 2 chargers was a limited pilot program implemented when there was less certainty about the future of electric vehicle ownership. It is now clear that such ownership is increasing but appears to be constrained by a lack of fast charging availability in Kentucky. Therefore, it is reasonable to expect that fast charging, which is an enabling technology for electric vehicle ownership, will help increase electric vehicle ownership in Kentucky and in particular among LG&E's customers. Therefore, deploying fast chargers will help serve LG&E's customers and will be a reasonable cost to include in rates in future rate proceedings.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 125

Responding Witness: William Steven Seelye

Q-125. Refer to the Seelye Testimony, page 65, lines 12–15. Provide a cost comparison, including the installation and O&M costs of the Level-2 and Level-3 Electric Vehicle Charge stations.

A-125. Below is an approximation of public dual-port charging station costs deployed through the EVC-L2 and EVC-Fast programs. Level 2 station costs are approximations of actual costs incurred. DCFC station costs are based on non-binding estimates solicited from vendors in a 2020 request for information.

	Dual-Port Level 2 Station	Dual-Port DCFC Station
Equipment & Installation	$15,300	$306,000
Annual O&M	$1,100	$5,000

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 126

Responding Witness: William Steven Seelye

Q-126. Refer to the Seelye Testimony, page 74, Table 4, which includes DC Fast Charging Rates from several out-of-state utilities. For these same utilities, provide a table showing what they charge for Level 2 charging services.

A-126.

Utility	Level 2 Charging Rate
Baltimore Gas and Electric Company (BG&E)	$0.18/kWh
Duke Energy Carolinas	N/A
Florida Power & Light (FPL)	N/A
Georgia Power Company	$1/hr for first 3 hours; $0.10/minute thereafter
Potomac Electric Power Company (PEPCO)	$0.18/kWh

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 127

Responding Witness: William Steven Seelye

Q-127. Refer to the Seelye Testimony, page 94, lines 13–22 and page 95, lines 1–17. Explain any differences in the calculation of the excess facilities charge from the 2018 rate case.

A-127. The only difference is that the Company's cost of capital has been updated.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 128

Responding Witness: Eileen L. Saunders

Q-128. Refer to the Seelye Testimony, page 99, line 4. Explain whether meter readers are contracted by LG&E or full time employees.

A-128. The Company expects to utilize employee meter readers to support the AMI opt out meter reading needs.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 129

Responding Witness: Robert M. Conroy

Q-129. Refer to the Seelye Testimony, page 101, lines 13–20. For the proposed General Time of Day Services, explain whether the number of participants will be limited and if so, what the limit is proposed to be.

A-129. See the testimony of Mr. Conroy at page 29. The General Time of Day Service (GTOD) tariffs will be limited to only those General Service customers currently participating in the Company's Advanced Metering System Customer Service Offering. If the Company's AMI proposal is approved, then as meter deployment occurs the Company will monitor customers' desire to participate in the GTOD rate to determine if conditions to participate should be revised.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 130

Responding Witness: William Steven Seelye

Q-130. Refer to the Seelye Testimony, Exhibit WSS-4. Provide cost support for the following:

a. Total Installed Cost;

b. Fixed Carrying Charge; and

c. Annual Non-Fixture Maintenance Cost.

A-130.

a. See attachment being provided in Excel format.

b. See attachment being provided in Excel format.

c. The annual non-fixture maintenance cost is based on the forecasted test year O&M cost to repair and replace defective fixtures of $464,634 divided by the number of fixtures (88,567).

The attachments are being provided in separate files in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 131

Responding Witness: William Steven Seelye

Q-131. Refer to the Seelye Testimony, Exhibit WSS-5. Provide cost support for the following:

a. Pole allocation factor; and

b. Depreciation Rate.

A-131.

a. The calculation of the pole allocation factor is shown below.

	Units	Average Investment Per Unit	Calculated Net book Value
Fixtures			
OH Fixtures	50,283	$ 641.17	$ 32,240,130.91
UG Fixtures	38,284	$ 459.01	$ 17,572,596.37
Total			$ 49,812,727.27
Poles			
Post Top - Decorative Smooth	29,334	$ 2,229.65	$ 65,404,553.10
Post Top - Historic Fluted	807	$ 2,764.04	$ 2,230,580.28
Contemporary (Short)	825	$ 2,518.52	$ 2,077,779.00
Contemporary (Tall)	1,075	$ 3,278.06	$ 3,523,914.50
Cobra	5,706	$ 3,775.51	$ 21,543,060.06
Wood Pole	6,444	$ 559.68	$ 3,606,577.92
Total			$ 98,386,464.86
Grand Total NBV			$ 148,199,192.13
Percent Fixtures			33.61%
Percent Poles			66.39%

b. The depreciation rate matches the number of years over which the remaining undepreciated balance will be recovered. The conversion fee will be billed for a 5-year period; therefore, the component (depreciation rate) of the conversion fee designed to recover the undepreciated balance must recover that balance over the 5 years in which the fee will be charged.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 132

Responding Witness: William Steven Seelye

Q-132. Refer to the Seelye Testimony, Exhibit WSS-10 at 1 of 2. Indicate how many DC Fast Charging Ports are located in LG&E's service territory.

A-132. There are two public DC Fast Charging locations (defined as offering charging speeds of 50 kW or greater) in LG&E service territory with a total of 16 ports. Both stations are accessible only to Tesla drivers.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 133

Responding Witness: William Steven Seelye

Q-133. Refer to the Seeley Testimony, Exhibit WSS-11.

a. Provide support for the estimated investment per unit.

b. Explain why fixed charges are estimated to be 20.70 percent of the investment.

c. Provide support for the O&M costs.

d. Provide support for the charge point cost.

A-133.

a. The investment per unit is the Companies' contract pricing for a Clipper Creek HCS-40R single-port charging station with the Share2 option and a branded LG&E or KU sticker applied to the station. The charging station and Share2 option pricing ($796.10 of the $800.85) was obtained via a competitive request for proposal solicited in 2019.

b. The fixed charge consists of the following components:

Cost of Capital	7.165%
Depreciation (10-year life)	10.000%
Income Taxes	1.768%
Property Taxes	1.770%
Total	**20.70%**

c. The annual O&M cost of $126.00 is an estimated amount for unplanned maintenance expenses. There are no planned maintenance costs associated with the Clipper Creek stations. In the absence of real-world unplanned maintenance cost data for Clipper Creek stations, the Company has chosen to include the unplanned maintenance costs proposed and approved in Case No. 2015-00355.

d. The Chargepoint Annual Cost for the Clipper Creek station detailed in Exhibit WSS-11 is $0. The Clipper Creek unit requires no ongoing annual network fees for operation.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 134

Responding Witness: William Steven Seelye

Q-134. Refer to the Seelye Testimony, Exhibit WSS-12, pages 3–4 of 4, Cost Support for Redundant Capacity Charge. Explain the derivation of the amounts listed under Billing Demand and Rate Base.

A-134. Billing Demand for the Power Service Secondary ("PSS") class was derived by summing the billed Summer Peak Demand of 1,860,125 kW with the billed Winter Peak Demand of 2,416,973 kW shown on page 6 of Schedule M-2.3-E for a total of 4,277,097 kW of billed demand.

Billing Demand for the Time-of-Day Secondary ("TODS") class is the Base Period Demand shown on page 8 of Schedule M-2.3-E totaling 4,406,484 kVA of billed demand. The rationale for choosing the Base Period demand is that those billings represent the recovery of distribution-related costs from TODS customers.

Billing Demand for the Power Service Primary ("PSP") class was derived by summing the billed Summer Peak Demand of 148,944 kW with the billed Winter Peak Demand of 191,122 kW shown on page 7 of Schedule M-2.3-E for a total of 340,066 kW of billed demand.

Billing Demand for the Time-of-Day Primary ("TODP") class is the Base Period Demand shown on page 9 of Schedule M-2.3-E totaling 5,354,606 kVA of billed demand. The rationale for choosing the Base Period demand is that those billings represent the recovery of distribution-related costs from TODP customers.

The Rate Base amounts are derived from the sum of Distribution Substation, Distribution Primary and Secondary Lines, and Distribution Transformers demand-related costs allocated to each respective class in the Cost-of-Service Study shown on Exhibit WSS-32. For PSS this is the sum of cells J143+J147+J154, for TODS it is the sum of cells L143+L147+L154, for PSP it is the sum of cells I143+I147+I154, and for TODP it is the sum of cells K143+K147+K154 on page 5 of Exhibit WSS-32.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 135

Responding Witness: William Steven Seelye

Q-135. Refer to the Seelye Testimony, Exhibit WSS-19, Cost Support for Miscellaneous Charges. Identify those services performed by LG&E employees and those services performed by contract labor. For those performed by contract labor, explain whether LG&E is charged a flat fee by the contractor or whether LG&E is charged per service performed.

A-135.

Electric Meter Test Charge
Electric meters are tested by both employees and contractors and are billed on an hourly basis.

Disconnect/Reconnect Service Charge:
Disconnects and Reconnects are performed by field services employees and contractors. Both work on an hourly labor basis.

Unauthorized Reconnect Charge:
Work on UARs is performed by a combination of employees and contractors. They are compensated on an hourly basis.

Gas Inspection Charge:
Gas Operations utilize contractors or employees, depending on resource availability, billed on an hourly basis.

Charge for Temporary and Short Term Service – Gas
Gas Operations utilize contractors or employees, depending on resource availability, billed on an hourly basis.

Additional Trip Charge – Gas:
Gas Operations utilize contractors or employees, depending on resource availability, billed on an hourly basis.

Gas Meter Pulse Service:
Meter Pulse Services are performed by employees and are billed on an hourly basis.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 136

Responding Witness: William Steven Seelye

Q-136. Refer to the Seelye Testimony, Exhibit WSS-19, page 3 of 18, Cost Justification for the Disconnect/Reconnect Fee. Provide detailed cost justification, broken down by component, for the amounts listed as "Disconnect Service" and "Reconnect Service."

A-136. The costs were determined based on actual expenses and service orders for March 2019 through February 2020, as adjusted for inflation, as shown below.

Adjusted Costs based on March 2019 through February Actual

Field Service Costs Recorded per Books	$ 5,478,813
Test Year Escalation Factor at 3% inflation	1.06090
Adjusted Test-Year Cost with Inflation Factor for test year	$ 5,812,473
Percentage Related to Disconnect/Reconnect (See below)	37.76%
Total Disconnect/Reconnect Cost	$ 2,194,546
Total Number of Disconect/Reconnect Orders	136,212
Cost per Disconnect or Reconnect Order	$ 16.11

	Orders	**% of Total**
Disconnect/Reconnect Service Orders	136,212	37.76%
Other Service Orders	224,559	62.24%
Total Orders	360,771	100.00%

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 137

Responding Witness: William Steven Seelye

Q-137. Refer to the Seelye Testimony, Exhibit WSS-19, page 5 of 18, Cost Justification for the Electric Meter Test Fee. Explain how the amounts listed as "Labor - One Hour" and "Vehicle - 2/3 Hour" were calculated and provide the detailed calculation.

A-137. The time required to perform the services was based on management estimates. The labor cost was derived from the hourly rate from the IBEW Contract plus the Company's standard burden rate, as escalated for inflation. See derivation of costs below.

Labor	
IBEW Hourly Rate	$ 41.12
Burden Rate	68.55%
Burdens	$ 28.19
Total Unadjusted Labor	$ 69.31
Test Year Escalation Factor at 3% inflation	1.06090
Total Labor Cost per Hour	$ 73.53
Time Required in Hours	1.00
Total Labor Cost	$ 73.53
Transportation	
Light Duty Pickup	$ 5.96
Medium & Heavy Duty Truck	8.78
Van	7.84
Average Cost	$ 7.53
Test Year Escalation Factor at 3% inflation	1.06090
Average Vehicle Cost per Hour	$ 7.99
Time Required in Hours	0.6667
Total Vehicle Cost	$ 5.32

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 138

Responding Witness: William Steven Seelye

Q-138. Refer to the Seelye Testimony, Exhibit WSS-19, page 6 of 18, Cost Justification for the Gas Meter Test Fee. Explain how the amounts listed as "Labor - One and one third hour" and "Meter Test - One hour" were calculated, provide the detailed calculation, and explain why no vehicle cost is included in this fee.

A-138. The time required to perform the services was based on management estimates. The labor cost was derived from the hourly rates of applicable job positions of employees performing the work, plus the Company's standard burden rate, as adjusted for inflation. See derivation of costs below.

Labor	
Hourly Rate	$ 26.28
Burden Rate	68.55%
Burdens	$ 18.01
Total Unadjusted Labor	$ 44.29
Test Year Escalation Factor at 3% inflation	1.06090
Total Labor Cost per Hour	$ 46.98
Time Required in Hours	1.20
Total Labor Cost	$ 56.38

Meter Test	
Prover Labor (0.5 x $38.83)	$ 19.42
Office Associates Labor (.25*$22.73)	5.6825
Total Labor	$ 25.10
Burden Rate	68.55%
Burdens	$ 17.21
Total Unadjusted Labor	$ 42.30
Test Year Escalation Factor at 3% inflation	1.06090
Total Labor Cost per Hour	$ 44.88
Time Required in Hours	1.00
Total Labor Cost	$ 44.88

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 139

Responding Witness: William Steven Seelye

Q-139. Refer to the Seelye Testimony, Exhibit WSS-19, page 7 of 18, Cost Justification for the Gas Inspection Charge/Additional Trip Charge. Explain how the amounts listed as "Labor" and "Transportation" were calculated and provide the detailed calculation.

A-139. The time required to perform the services was based on management estimates. The labor cost was derived from the hourly rates of applicable job positions of employees performing the work, plus the Company's standard burden rate, as adjusted for inflation. See derivation of costs below.

Labor	
LG&E Crew Leader	$ 42.00
LG&E Mechanic	40.16
Total	$ 82.16
Burden Rate	68.55%
Burdens	$ 56.32
Total Unadjusted Labor	$ 138.48
Test Year Escalation Factor at 3% inflation	1.06090
Total Labor Cost per Hour	$ 146.92
Time Required in Hours	1.00
Total Labor Cost	$ 146.92

Transportation	
Van	$ 7.84
Test Year Escalation Factor at 3% inflation	1.06090
Average Vehicle Cost per Hour	$ 8.32
Time Required in Hours	0.6667
Total Vehicle Cost	$ 5.54

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 140

Responding Witness: William Steven Seelye

Q-140. Refer to the Seelye Testimony, Exhibit WSS-19, page 10 of 18, Cost Justification for the Meter Pulse Electric Charge. Provide supporting documentation for each amount listed in the cost justification.

A-140. See attachment being provided in Excel format.

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 141

Responding Witness: William Steven Seelye

Q-141. Refer to the Direct Seelye Testimony, Exhibit WSS-19, page 11 of 18, Cost Justification for the Meter Pulse Gas Charge. Provide supporting documentation for each amount listed in the cost justification, explain why the labor and vehicle amounts for the two different charges are not the same, and explain why the Total Cost at April 30, 2018 is used for the FT and TS-2 customer without telemetry.

A-141. See attachment being provided in Excel format. The line shown as "Total Cost at April 30, 2018" was mislabeled. The line should have been labeled "Total Cost at July 31, 2020."

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 142

Responding Witness: William Steven Seelye

Q-142. Refer to the Seelye Testimony, Exhibit WSS-19, page 13 of 18, Cost Justification for the Electric Unauthorized Meter Reconnect Charge. Provide supporting documentation for each amount listed in the cost justification, and explain why the multiple amounts listed as "Charge without meter replacement" do not match the amount listed as "Total Charge without meter replacement at July 31, 2020" and are different for each charge.

A-142. Supporting calculations for the charges are shown below. Documents supporting the cost of the meters and locks are included in separate attachments to this response. The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection. The support for the meter cost estimates is shown in the following cells or sections of the referenced documents:

Description	Avg Cost Of Meter	Reference (Excel Spreadsheet or PDF)
1/0 Standard	$20	In "2020 PSC DR2 LGE Attach to Q142 – Att 2 Itron Bid Analysis Confidential.xlsx" (cells B7, B9, B19, B21:B22, B26, and B28:B29, with cell B19 being the most common) as part of the 2020 electric RFP
1/0 AMR	$40	In "2020 PSC DR2 LGE Attach to Q142 – Att 2 Itron Bid Analysis Confidential.xlsx" (cells B8, B20, and B27, with cell B19 being the most common) as part of the 2020 electric RFP
1/0 AMS	$100	In "2020 PSC DR2 LGE Attach to Q142 – Att 3 Landis+Gyr Confidential.xlsx" (cells B11, B26, and B35, with cell B26 being the most common) as part of the 2020 electric RFP
3/0 Standard	$105	In "2020 PSC DR2 LGE Attach to Q142 – Att 2 Itron Bid Analysis Confidential.xlsx" (cells B11, B26, and B35, with cell B26 being the most common) as part of the 2020 electric RFP

Description	**Avg Cost Of Meter**	**Reference (Excel Spreadsheet or PDF)**
Gas Meter	$62	See "2020 PSC DR2 LGE Attach to Q142 – Att 1 Honeywell Email Confidential.pdf"
Lock	$11	See "2020 PSC DR2 LGE Attach to Q142 – Att 4 Lock Invoices Confidential.pdf"

The reason that the charges without meter replacement differ from those with meters is that different weighted inflation factors are utilized for the categories depending on the relationship of equipment to labor. Specifically, a 3% escalation rate was used for labor expenses and a 2% escalation rate was used for equipment costs. Therefore, different weighted escalation rates were calculated based on the relative amounts of labor and equipment included in each type of Unauthorized Meter Reconnect Charge. See calculations below:

Charge Without Meter Replacement	
Field Services	
Labor Cost per Hour	$ 35.00
Burden Rate	68.55%
Burdens	$ 23.99
Total Labor Cost per Hour	$ 58.99
Time Required in Hours	0.25
Total Field Services Labor Cost	$ 14.75
Transportation	
Light Duty Pickup	$ 5.96
Time Required in Hours	0.2500
Total Vehicle Cost	$ 1.49
Back Office Admin Labor	
Hourly Rate	$ 22.40
Burden Rate (SERVCO)	72.18%
Burdens	$ 16.17
Total Unadjusted Labor	$ 38.57
Time Required in Hours	0.50
Total Back-Office Labor Cost	$ 19.28
Lock Box	
Cost of Lock Bock (See attachment to response)	$ 11.00
Total - Unadjusted	$ 46.52
Test Year Escalation Factor at 2.76% inflation (76% Labor x 3% + 24% Equipment x 2% = 2.76%)	1.0560
Total - Adjusted for Inflation	$ 49.13

Charge if Standard 1/0 Meter Replacement is Necessary

Charge Without Meter Replacement -- Unadjusted	$ 46.52
Cost of Standard 1/0 Meter (See attachment to response)	$ 20.00
Total - Unadjusted	$ 66.52
Test Year Escalation Factor at 2.70% inflation (70% Labor x 3% + 30% Equipment x 2% = 2.70%)	1.0547
Total - Adjusted for Inflation	$ 70.16

Charge if 1/0 AMR Meter Replacement is Necessary

Charge Without Meter Replacement -- Unadjusted	$ 46.52
Cost of 1/0 AMR Meter (See attachment to response)	$ 40.00
Total - Unadjusted	$ 86.52
Test Year Escalation Factor at 2.54% inflation (54% Labor x 3% + 46% Equipment x 2% = 2.54%)	1.0514
Total - Adjusted for Inflation	$ 90.97

Charge if 1/0 AMS Meter Replacement is Necessary

Charge Without Meter Replacement -- Unadjusted	$ 46.52
Cost of 1/0 AMS Meter (See attachment to response)	$ 100.00
Total - Unadjusted	$ 146.52
Test Year Escalation Factor at 2.32% inflation (32% Labor x 3% + 68% Equipment x 2% = 2.32%)	1.0469
Total - Adjusted for Inflation	$ 153.39

Charge if 3/0 Standard Meter Replacement is Necessary

Charge Without Meter Replacement -- Unadjusted	$ 46.52
Cost of 3/0 Standard Meter (See attachment to response)	$ 105.00
Total - Unadjusted	$ 151.52
Test Year Escalation Factor at 2.31% inflation (31% Labor x 3% + 69% Equipment x 2% = 2.31%)	1.0467
Total - Adjusted for Inflation	$ 158.60

The entire attachment is Confidential and provided separately under seal.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information Dated January 8, 2021

Case No. 2020-00350

Question No. 143

Responding Witness: William Steven Seelye

Q-143. Refer to the Seelye Testimony, Exhibit WSS-19, page 13 of 18, Cost Justification for the Electric Unauthorized Meter Reconnect Charge. Provide the remaining cost justification for the "UAR Charge for 1/0 AMS Meter Replacement".

A-143. See the response to Question No. 142.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Commission Staff's Second Request for Information
Dated January 8, 2021**

Case No. 2020-00350

Question No. 144

Responding Witness: William Steven Seelye

Q-144. Refer to the Seelye Testimony, Exhibit WSS-19, page 14 of 18, Cost Justification for the Gas Unauthorized Meter Reconnect Charge. Provide supporting documentation for each amount listed in the cost justification and explain why the amount listed as "Charge without meter replacement" under the "Total Charge if meter replacement is necessary" is not the same as the amount listed as "Total Charge without meter replacement at July 31, 2020."

A-144. Supporting calculations for the charges are shown below. Documents supporting the cost of the meters and locks are included in the response to Question No. 142.

The reason that the charges without meter replacement differ from those with meters is that different weighted escalation factors are utilized for the categories depending on the relationship of equipment to labor. Specifically, a 3% escalation rate was used for labor expenses and a 2% escalation rate was used for equipment costs. Therefore, different weighted escalation rates were calculated based on the relative amounts of labor and equipment included in each type of Unauthorized Meter Reconnect Charge. See calculations below.

Charge Without Meter Replacement

Field Services	
Labor Cost per Hour	$ 35.00
Burden Rate	68.55%
Burdens	$ 23.99
Total Labor Cost per Hour	$ 58.99
Time Required in Hours	0.25
Total Field Services Labor Cost	$ 14.75
Transportation	
Light Duty Pickup	$ 5.96
Time Required in Hours	0.2500
Total Vehicle Cost	$ 1.49
Back Office Admin Labor	
Hourly Rate	$ 22.40
Burden Rate (SERVCO)	72.18%
Burdens	$ 16.17
Total Unadjusted Labor	$ 38.57
Time Required in Hours	0.50
Total Back-Office Labor Cost	$ 19.28
Lock Box	
Cost of Lock Bock (See attachment to response)	$ 11.00
Total - Unadjusted	$ 46.52
Test Year Escalation Factor at 2.76% inflation (76% Labor x 3% + 24% Equipment x 2% = 2.76%)	1.0560
Total - Adjusted for Inflation	$ 49.13

Charge If Standard Meter Replacement Is Necessary

Charge Without Meter Replacement -- Unadjusted	$ 46.52
Cost of Standard Meter (See attachment to response)	$ 62.00
Total - Unadjusted	$ 108.52
Test Year Escalation Factor at 2.43% inflation (43% Labor x 3% + 57% Equipment x 2% = 2.43%)	1.0492
Total - Adjusted for Inflation	$ 113.86

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 145

Responding Witness: William Steven Seelye

Q-145. Refer to the Seelye Testimony, Exhibit WSS-26. Also refer to WSS-23 of the 2018 Rate Case. The zero-intercept analysis for Account 365 – Overhead Conductor estimates the customer-related costs to account for 63.99 percent of the total and in the 2018 Rate Case, the customer-related estimates were 61.71 percent. Explain the increase in the customer-related costs.

A-145. Due to the statistical nature of the analysis and the changes in the size and quantity of overhead conductor on the Company's system, the costs classified as customer-related will have inherently changed as conductor types are added to and retired from the Company's distribution system.

Changes in customer-related costs calculated by the zero-intercept analysis are based on the changes in both the quantity of each conductor type installed by the Company and the contribution of the costs of each type of conductor. These conductor quantities and costs are weighted based on their contribution to the overall cost of the conductor included in the analysis and to the extent that the zero intercept value changes it will have an impact on how much of the total cost is classified as customer-related.

In this case, the zero-intercept calculated from the overhead conductor analysis was \$1.38 per foot of conductor with a slope of \$0.00417/MCM of conductor size. In the Company's 2018 rate case, the zero-intercept was \$1.27 per foot of conductor with a slope of \$0.00423/MCM. This means that the analysis calculated more cost per foot of conductor associated with the non-size related portion of each conductor type than in 2018 thus increasing the overall percentage of costs classified as customer-related.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 146

Responding Witness: William Steven Seelye

Q-146. Refer to the Seelye Testimony, Exhibit WSS-27. Also refer to WSS-24 of the 2018 Rate Case. The zero-intercept analysis for Account 367 – Underground Conductor estimates the customer-related costs to account for 59.86 percent of the total and in the 2018 Rate Case, the customer-related estimates were 60.96 percent. Explain the decrease in the customer-related costs.

A-146. Due to the statistical nature of the analysis and the changes in the size and quantity of underground conductor on the Company's system, the costs classified as customer-related will have inherently changed as conductor types are added to and retired from the Company's distribution system.

Changes in customer-related costs calculated by the zero-intercept analysis are based on the changes in both the quantity of each conductor type installed by the Company and the contribution of the costs of each types of conductor. These conductor quantities and costs are weighted based on their contribution to the overall cost of the conductor included in the analysis and to the extent that the zero intercept value changes it will have an impact on how much of the total cost is classified as customer-related.

In this case, the zero-intercept calculated from the underground conductor analysis was $3.60 per foot of conductor with a slope of $0.012/MCM of conductor size. In the Company's 2018 rate case, the zero-intercept was $3.57 per foot of conductor with a slope of $0.012/MCM. This means that the analysis calculated more cost per foot of conductor associated with the non-size related portion of each conductor type than in 2018 thus increasing the overall percentage of costs classified as customer-related.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 147

Responding Witness: William Steven Seelye

Q-147. Refer to the Seelye Testimony, Exhibit WSS-28. Also refer to WSS-25 of the 2018 Rate Case. The zero-intercept analysis for Account 368 – Line Transformers estimates the customer-related costs to account for 35.79 percent of the total and in the 2018 Rate Case, the customer-related estimates were 61.71 percent. Explain the decrease in the customer-related costs.

A-147. For purposes of clarification, in the Company's 2018 rate case the customer-related costs for Account 368 – Line Transformers was 36.88 percent, and this Rate Case is 35.79 percent, resulting in a 1.09% decrease in customer-related costs.

Due to the statistical nature of the analysis and the changes in the size and quantity of transformers on the Company's system, the costs classified as customer-related will have inherently changed as transformer types are added to and retired from the Company's distribution system.

Changes in customer-related costs calculated by the zero-intercept analysis are based on the changes in both the quantity of each transformer type installed by the Company and the contribution of the costs of each types of conductor. These transformer quantities and costs are weighted based on their contribution to the overall cost of the transformers included in the analysis and to the extent that the zero intercept value changes it will have an impact on how much of the total cost is classified as customer-related.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 148

Responding Witness: William Steven Seelye

Q-148. Refer to the Seelye Testimony, Exhibit WSS-30, page 29 of 30. Explain how the external functional vector of Poles, Towers, and Fixtures was determined.

A-148. The Poles, Towers and Fixtures functional vector is equivalent to the Overhead Conductor external functional vector. Given that poles, towers and fixtures are principally installed to support overhead conductor and associated equipment, it is assumed that the split between demand and customer-related costs for Account 364 is equivalent to that of the Overhead Conductor FERC Account 365.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information Dated January 8, 2021

Case No. 2020-00350

Question No. 149

Responding Witness: William Steven Seelye

Q-149. Refer to the Seelye Testimony, Exhibit WSS-35, Allocation of High Pressure and Low/Medium Pressure Mains.

a. Explain why different degree days were used for the residential and commercial rate classes than for the industrial and transportation rate classes.

b. Explain why the calculated daily customer deliveries was calculated at -14 degrees or 79 heating degree days.

c. Also refer to Exhibit WSS-38, Allocation of Underground Storage.

(1) Explain why the calculated daily requirements are at 4 degrees or 61 heating degree days.

(2) Explain why the number of degree days differs from Exhibit WSS-35.

A-149.

a. Residential and commercial classes are billed on a billing cycle basis while industrial and transportation classes are billed on a calendar month basis. The days in the year for cycle billed classes will be slightly different than the days in the year for classes billed on a calendar month resulting in different heating degree days.

b. LG&E uses 79 heating degree days (or -14° F) for distribution and gas supply planning purposes, which represents the lowest daily temperature that would likely occur during a 50-year period.

c.

(1) LG&E uses multiple design days throughout the winter season for its gas supply planning and gas storage inventory management. February 26 is the late winter design day for storage withdrawals and is based on 61 heating degree days. LG&E must maintain adequate natural gas storage inventory to serve this late-winter design day.

(2) The heating degree days are different because the gas distribution system is planned on a single design day of 79 heating degree days, representative of the lowest temperature that would likely occur during a winter season, whereas the gas storage system is designed around multiple design days. The late winter design day on February 26 is based on 61 heating degree days.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 150

Responding Witness: Robert M. Conroy / William Steven Seelye

Q-150. Refer to LG&E's response to Commission Staff's First Request for Information, Item 54. Provide cost support for LG&E's forfeited discounts/late payment charge.

A-150. LG&E reduced the late payment charge from 5% to the current level of 3% for Rates RS and GS in the Settlement Agreement that was filed with the Commission on November 19, 2012 in Case No. 2012-00222. The Settlement Agreement was approved by the Commission in its Order dated December 20, 2012. No cost support was developed at that time nor since to support the settled rate. Ultimately, the late payment charge is intended to be an inducement to encourage customers to pay their bills on time. Without such an inducement to pay on time, behavior of some customers could change in a way that adversely impacts on time payment.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 151

Responding Witness: Christopher M. Garrett

Q-151. Refer to LG&E's response to Commission Staff's First Request for Information, Item 54.

a. For the base period, explain why the recovered charges exceed the billed charges in the Forfeited Discounts/Late Payment Charges column in both the Electric and Gas Summary of Nonrecurring Charges.

b. Explain what is included in the "Other Service Charge" column of both the Electric and Gas Summary of Nonrecurring Charges, provide a breakdown by each charge included in that column, and explain if those services are performed by LG&E employees or by contract labor.

c. For the base period, explain why the recovered charges in the Unauthorized Reconnect Charge column are negative in the Gas Summary of Nonrecurring Charges.

A-151.

a. The recovered charges exceed the billed charges in Forfeited Discounts/Late Payment Charges column in the base period as a result of the timing difference in recoveries and billings due to the lag in collections. The base period billed charges are for bills rendered from March 1, 2020 through March 16, 2020, while recoveries include collections received from March 1, 2020 through August 31, 2020 for billed charges prior to March 16, 2020. While the billing of late payment charges stopped effective March 16, 2020, the recovery/collections of late payment charges continued for the balance of the base period with the majority of the collections occurring in March, April and May.

b. Other Services include electric and gas meter test charges, electric and gas meter pulse charges, gas inspection charges and temporary to permanent and seasonal service charges. All of these services, except gas meter pulses, are performed by both LG&E employees and contract labor depending on availability. Gas meter pulses are performed only by LG&E employees.

c. In preparation of the response to this data request, a formula error was discovered in the supporting file resulting in the recoveries amounts provided for the Base Period for unauthorized reconnect charges to be incorrect. The updated unauthorized reconnect recoveries amounts for LG&E Electric and LG&E Gas for the Base Period were $44,016 and $3,878, respectively.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 152

Responding Witness: Daniel K. Arbough

Q-152. Refer to LG&E's response to Commission Staff's First Request for Information, Item 56, Schedule C. Provide a breakdown or supporting schedules for Account 404 in the test year.

A-152.

Description	**YE Jun-22** Amortization Expense
LGE- Electric	
LGE-330300-Misc Intangible Plant- (Software, licenses and other intangible property)	$ 14,828,811.33
LGE-330310-CCS Software	916,664.19
LGE-330330-Cloud Software Non- Current	256,900.80
	$ 16,002,376.32
LGE- Gas	
LGE-230200-Franchises and Consents	$ 48.00
LGE-330300-Misc Intangible Plant – (Software, licenses and other intangible property)	6,662,219.59
LGE-330310-CCS Software	411,834.65
LGE-330330-Cloud Software Non - Current	115,419.24
Account 404 – LGE Gas	$ 7,189,521.48
Total LG&E Company	$ 23,191,897.80

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 153

Responding Witness: Robert M. Conroy

Q-153. Provide a table illustrating the customer charges for the last six rate cases as well as the percentage increase between each rate case.

A-153. See attached.

LG&E							
		RS		RTOD-E		RTOD-D	
Rate Case	Case Number	Customer Charge per month	% Change	Customer Charge per month	% Change	Customer Charge per month	% Change
2020 Rate Case	2020-00350	$ 15.83	16%	$ 15.83	16%	$ 15.83	16%
2018 Rate Case	2018-00295	$ 13.70	12%	$ 13.70	12%	$ 13.70	12%
2016 Rate Case	2016-00371	$ 12.25	14%	$ 12.25	14%	$ 12.25	14%
2014 Rate Case	2014-00372	$ 10.75	0%	$ 10.75		$ 10.75	
2012 Rate Case	2012-00222	$ 10.75	26%	N/A		N/A	
2010 Rate Case	2009-00549	$ 8.50		N/A		N/A	

LG&E							
		VFD		**GS-Single Phase**		**GS-Three Phase**	
Rate Case	Case Number	Customer Charge per month	% Change	Customer Charge per month	% Change	Customer Charge per month	% Change
2020 Rate Case	2020-00350	$ 15.83	16%	$ 35.31	12%	$ 56.31	11%
2018 Rate Case	2018-00295	$ 13.70	12%	$ 31.66	0%	$ 50.53	0%
2016 Rate Case	2016-00371	$ 12.25	14%	$ 31.50	26%	$ 50.40	26%
2014 Rate Case	2014-00372	$ 10.75	0%	$ 25.00	25%	$ 40.00	14%
2012 Rate Case	2012-00222	$ 10.75	26%	$ 20.00	14%	$ 35.00	8%
2010 Rate Case	2009-00549	$ 8.50	-	$ 17.50	-	$ 32.50	-

LG&E							
		PS-Secondary		**PS-Primary**		**TODS**	
Rate Case	Case Number	Customer Charge per month	% Change	Customer Charge per month	% Change	Customer Charge per month	% Change
2020 Rate Case	2020-00350	$ 90.10	0%	$ 240.15	0%	$ 200.28	0%
2018 Rate Case	2018-00295	$ 90.10	0%	$ 240.15	0%	$ 200.28	0%
2016 Rate Case	2016-00371	$ 90.00	0%	$ 240.00	20%	$ 200.00	0%
2014 Rate Case	2014-00372	$ 90.00	0%	$ 200.00	18%	$ 200.00	0%
2012 Rate Case	2012-00222	$ 90.00	0%	$ 170.00	89%	$ 200.00	0%
2010 Rate Case	2009-00549	$ 90.00	-	$ 90.00	-	$ 200.00	-

LG&E							
		TODP		**RTS**		**FLS Primary**	
Rate Case	Case Number	Customer Charge per month	% Change	Customer Charge per month	% Change	Customer Charge per month	% Change
2020 Rate Case	2020-00350	$ 329.94	0%	$ 1,499.96	0%	$ 329.94	0%
2018 Rate Case	2018-00295	$ 329.94	0%	$ 1,499.96	0%	$ 329.94	0%
2016 Rate Case	2016-00371	$ 330.00	10%	$ 1,500.00	50%	$ 330.00	-67%
2014 Rate Case	2014-00372	$ 300.00	0%	$ 1,000.00	33%	$ 1,000.00	33%
2012 Rate Case	2012-00222	$ 300.00	0%	$ 750.00	50%	$ 750.00	50%
2010 Rate Case	2009-00549	$ 300.00	-	$ 500.00	-	$ 500.00	-

LG&E			
		FLS Transmission	
Rate Case	Case Number	Customer Charge per month	% Change
2020 Rate Case	2020-00350	$ 1,499.96	0%
2018 Rate Case	2018-00295	$ 1,499.96	0%
2016 Rate Case	2016-00371	$ 1,500.00	50%
2014 Rate Case	2014-00372	$ 1,000.00	33%
2012 Rate Case	2012-00222	$ 750.00	50%
2010 Rate Case	2009-00549	$ 500.00	

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 154

Responding Witness: William Steven Seelye

Q-154. Regarding both the electric and gas cost of service studies:

a. Provide any significant differences in the allocation factors between the instant case and the 2018 Rate Case.

b. Provide any differences between the current LOLP COSS and the LOLP COSS filed with the 2018 Rate Case.

A-154.

a. There are no significant differences in the allocation factors that were used to prepare the electric or gas cost of service study in this case and those used in the 2018 Rate Case.

b. There are no differences between the LOLP methodology that was used to prepare the LOLP COSS filed in 2018 as compared to the LOLP COSS methodology filed in this proceeding.

   Any differences in the LOLP allocation factors between the two COSS are a result of differences in the input data for the LOLP calculations such as class loads, system loads, and generating unit characteristics including forced outage rates.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 155

Responding Witness: Robert M. Conroy

Q-155. Provide any study regarding low-income usage as compared to the average user.

A-155. The Company does not maintain income level by customer. However, see attachment being provided in Excel format for a monthly comparison of residential customer usage as a class for 2019 and 2020 to the usage of residential customers receiving assistance funding for utility bills.

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 156

Responding Witness: William Steven Seelye

Q-156. Provide a comparison table of the cost component estimates from each COSS for each rate class.

A-156. See attached.

Louisville Gas and Electric Company Units Costs from Cost of Service Study based on Proposed Rate of Return for each Rate Class

LOLP	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary	Rate RTS Transmission	Special Contract Customer
Demand Costs ($/kW or $/kwh)	$0.063706/kWh	$0.086804/kWh	$27.11/kW	$23.57/kW	$19.62/kW	$20.72/kW	$16.98/kW	$19.99/kW
Energy Costs ($/kWh)	$0.032447	$0.033395	$0.033000	$0.033360	$0.032353	$0.032921	$0.031828	$0.032281
Customer Costs (per customer per day)	$0.69	$1.41	$7.18	$2.49	$8.96	$4.79	$42.30	$6.37

12CP	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary	Rate RTS Transmission	Special Contract Customer
Demand Costs	$0.062054/kWh	$0.087486/kWh	$27.23/kW	$23.64/kW	$19.75/kW	$20.89/kW	$17.20/kW	$20.13/kW
Energy Costs	$0.032548	$0.033308	$0.032762	$0.033175	$0.032225	$0.032797	$0.031516	$0.032001
Customer Costs	$0.74	$1.36	$6.83	$2.39	$8.76	$4.70	$39.60	$5.97

6CP	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary	Rate RTS Transmission	Special Contract Customer
Demand Costs	$0.062664/kWh	$0.087697/kWh	$27.19/kW	$23.62/kW	$19.66/kW	$20.83/kW	$17.07/kW	$20.09/kW
Energy Costs	$0.032511	$0.033280	$0.032845	$0.033214	$0.032314	$0.032841	$0.031696	$0.032079
Customer Costs	$0.72	$1.35	$6.95	$2.42	$8.90	$4.73	$41.16	$6.08

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 157

Responding Witness: William Steven Seelye

Q-157. State whether LG&E is aware of a LOLP COSS being approved in other state jurisdictions. If so, provide the state and docket number.

A-157. Mr. Seelye has not performed a review of the cost-of-service studies approved in most other jurisdictions, but he is unaware of an LOLP COSS being approved in other jurisdictions. However, the LOLP methodology is identified in the NARUC *Electric Utility Cost Allocation Manual*, at page 62, as a reasonable methodology for allocating production fixed costs in an embedded cost of service study. See attached.

ELECTRIC UTILITY COST ALLOCATION MANUAL

January, 1992

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

1101 Vermont Avenue NW
Washington, D.C. 20005
USA
Tel: (202) 898-2200
Fax: (202) 898-2213
www.naruc.org

$25.00

demands are the primary determinants of baseload production plant costs, as indicated by the inter-class allocation of these costs, then they should also be classified as energy-related and recovered via an energy charge. Failure to do so -- i.e., classifying production plant costs as demand-related and recovering them through a $/KW demand charge -- will result in a disproportionate assignment of costs to low load factor customers within classes, inconsistent with the basic premise of the method.

3. LOLP Production Cost Method

LOLP is the acronym for loss of load probability, a measure of the expected value of the frequency with which a loss of load due to insufficient generating capacity will occur. Using the LOLP production cost method, hourly LOLP's are calculated and the hours are grouped into on-peak, off-peak and shoulder periods based on the similarity of the LOLP values. Production plant costs are allocated to rating periods according to the relative proportions of LOLP's occurring in each. Production plant costs are then allocated to classes using appropriate allocation factors for each of the three rating periods; i.e., such factors as might be used in a BIP study as discussed above. This method requires detailed analysis of hourly LOLP values and a significant data manipulation effort.

4. Probability of Dispatch Method

The probability of dispatch (POD) method is primarily a tool for analyzing cost of service by time periods. The method requires analyzing an actual or estimated hourly load curve for the utility and identifying the generating units that would normally be used to serve each hourly load. The annual revenue requirement of each generating unit is divided by the number of hours in the year that it operates, and that "per hour cost" is assigned to each hour that it runs. In allocating production plant costs to classes, the total cost for all units for each hour is allocated to the classes according to the KWH use in each hour. The total production plant cost allocated to each class is then obtained by summing the hourly cost over all hours of the year. These costs may then be recovered via an appropriate combination of demand and energy charges. It must be noted that this method has substantial input data and analysis requirements that may make it prohibitively expensive for utilities that do not develop and maintain the required data.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 158

Responding Witness: Daniel K. Arbough

Q-158. Provide an itemized list of all COVID-19 costs included in the base year and test year.

A-158. For the base period the Company incurred costs primarily for outside services required for additional cleaning and disinfecting of Company facilities, incremental costs associated with inspections and necessary repairs/tree trimming of circuits serving hospitals as well as convenience charges for credit and debit card, and e-check costs that the Company absorbed for the second quarter while business offices were closed to in-person traffic. Other significant costs include purchasing of hand sanitizer, thermometers, and personal protective equipment for employee usage as well as costs incurred to be prepared to sequester employees at power generation plants and control rooms for transmission and distribution operations. There are also small amounts of labor related to employees working specifically on COVID-19 related matters such as taking temperatures of incoming employees and contractors or filling in for someone having to quarantine due to exposure to the virus. The table below presents a breakdown of the LG&E base period costs:

Expense Type	**Base Period**
Outside Services and Contractors	$ 902,951
Convenience Payments Absorbed	530,844
Office Supplies and Equipment	467,901
Materials (including Safety Materials)	456,535
Labor	102,334
Meals	40,311
Transportation	32,967
Freight	10,400
Telecom	4,412
Software	2,425
Other	2,306
	$ 2,553,386

For the test year period refer to the testimony of Mrs. Saunders for the impacts to expenses for the additional costs of cleaning for facilities, of which $180,000 is allocated to LG&E.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 159

Responding Witness: Daniel K. Arbough

Q-159. Provide an itemized list of all COVID-19 benefits included in the base year and test year.

A-159. The Company has defined benefits for the purpose of this question as O&M cost reductions primarily related to training, travel and associated meals. This was derived as the difference between actual versus budget for the months March through August and forecasted lower spend compared to budget for the months September through December. While not all costs can be attributed to COVID-19, the restrictions put in place because of COVID-19 have significantly limited the amount of training courses offered due to distancing rules and in turn impacted travel and meal costs. For the base period reductions related to training, travel and meals totaled $1,281,482 for LG&E. When compiling the budget for the periods starting 2021, the forecast was not adjusted to reflect the potential of COVID-19 restrictions on training, travel and meals.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 160

Responding Witness: Robert M. Conroy

Q-160. Provide the number of times a month for 2019 and 2020 that visitors to LG&E's website: https://lge-ku.com/regulatory/rates-and-tariffs have viewed or downloaded the PDFs for LG&E electric rates and LG&E gas rates.

A-160. The following chart displays the number of viewing or downloads by month related to the Company's rates-and-tariffs website and LG&E electric and gas rates.

LG&E Electric Rates		
	2019	**2020**
Jan	230	289
Feb	252	155
Mar	228	89
Apr	254	94
May	301	106
Jun	246	106
Jul	303	96
Aug	284	163
Sep	284	236
Oct	320	379
Nov	259	306
Dec	286	382

LG&E Gas Rates		
	2019	**2020**
Jan	102	62
Feb	96	36
Mar	83	12
Apr	60	38
May	68	26
Jun	71	18
Jul	52	14
Aug	35	33
Sep	74	40
Oct	89	89
Nov	60	79
Dec	89	8

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00350

Question No. 161

Responding Witness: Daniel K. Arbough

Q-161. Provide any internal investment proposals prepared for projects included in rate base or CWIP in the past two years.

A-161. See attached. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.