COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC. FOR: 1) AN ADJUSTMENT OF THE ELECTRIC RATES; 2) APPROVAL OF NEW TARIFFS; 3) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND 4) ALL OTHER REQUIRED APPROVALS AND RELIEF	)	CASE NO. 2019-00271

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS FROM DUKE ENERGY KENTUCKY, INC.

Comes now the intervenor, the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("Attorney General"), and submits the following responses to data requests from Duke Energy Kentucky, Inc. (hereinafter "DEK" or the "Company") in the above-styled matter.

Respectfully submitted,

DANIEL CAMERON
ATTORNEY GENERAL

JUSTIN M. McNEIL
LAWRENCE W. COOK
ASSISTANT ATTORNEYS GENERAL
700 CAPITOL AVE, SUITE 20
FRANKFORT, KY 40601-8204
PHONE: (502) 696-5453
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Justin.McNeil@ky.gov
Larry.Cook@ky.gov

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

RICHARD A. BAUDINO, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Richard A. Baudino

Richard A. Baudino

Sworn to and subscribed before me on this 17th day of January 2020.

Notary Public

RANDY A. FUTRAL
MY COMMISSION EXPIRES
NOTARY
PUBLIC
AUGUST 26, 2020
COBB COUNTY, GEORGIA

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

LANE KOLLEN, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Lane Kollen

Sworn to and subscribed before me on this
17th day of January 2020.

Notary Public

RANDY A. FUTRAL
MY COMMISSION EXPIRES
NOTARY
PUBLIC
AUGUST 25, 2020
COBB COUNTY, GEORGIA

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of: THE ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC. FOR: 1) AN ADJUSTMENT OF THE ELECTRIC RATES; 2) APPROVAL OF NEW NEW TARIFFS; 3) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND 4) ALL OTHER REQUIRED APPROVALS AND RELIEF	)))))))))	CASE NO. 2019-00271

AFFIDAVIT OF Glenn A. Watkins

Commonwealth of Virginia	)))

Glenn A. Watkins, being first duly sworn, states the following: The prepared Data Request Responses, Schedules and Exhibits attached thereto were prepared by him or under his direct supervision. Affiant states that he would give the answers set forth in the Data Request Responses if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, information and belief, his statements made are true and correct. Further affiance sayeth naught.

G. A. Watt

SUBSCRIBED AND SWORN to before me this 16th day of January, 2020.

Jennifer R Dolen
NOTARY PUBLIC

My Commission Expires: 10/31/2022

JENNIFER R. DOLEN
NOTARY PUBLIC
REG # 7315146
MY COMMISSION EXPIRES 10/31/2022
COMMONWEALTH OF VIRGINIA

WITNESS/RESPONDENT RESPONSIBLE:
Counsel as to objection

QUESTION No. 1
Page 1 of 1

Does the Attorney General have a Joint Defense Agreement with any party to this proceeding?

(a) If the answer is in the affirmative, provide a copy of said agreement.

(b) If the answer is in the negative, please state whether the Attorney General has had any conversations with any Intervening Party to this proceeding regarding the company's rate application, revenue requirements, adjustments to the Company's revenue requirements, etc.

(c) If the answer is in the negative, has Mr. Kollen had any conversations related to the pending case with any other party to his proceeding?

(d) If the answer is in the affirmative, provide a list of all such conversations, the dates, copies of any emails, letters, opinions, studies, etc. that depict the nature of any conversations between Mr. Kollen and any other party to this proceeding.

RESPONSE:

Objection. These questions seek information that is not relevant to the proceeding. Whether or not the Attorney General has a Joint Defense Agreement or whether he or his experts have had "conversations" with other parties is immaterial to whether or not Duke Energy Kentucky's rates are fair, just, and reasonable. Furthermore, the Attorney General objects to the questions on the basis of Attorney-Client and/or work product privilege(s). Without waiving such objections, the Attorney General states: No, he does not have a Joint Defense Agreement with any party to this proceeding.

WITNESS/RESPONDENT RESPONSIBLE:
Counsel as to objection

QUESTION No. 2
Page 1 of 1

> Other than Messrs. Watkins, Kollen, and Baudino, please identify any persons, including experts whom the Attorney General has consulted, retained, or is in the process of retaining with regard to evaluating the Company's Application in this proceeding.

RESPONSE:

Objection. The question seeks information that is not relevant to the proceeding, and which would violate the work product and/or attorney-client privilege(s). Without waiving such objections, the Attorney General states as follows: None.

WITNESS/RESPONDENT RESPONSIBLE:
Counsel as to objection

QUESTION No. 3
Page 1 of 1

> For each person identified in (prior) response to Interrogatory No. 2 above, please state (1) the subject matter of the discussions/consultations/evaluations; (2) the written opinions of such persons regarding the Company's Application; (3) the facts to which each person relied upon; and (4) a summary of the person's qualifications to render such discussions/consultations/evaluations.

RESPONSE:

The Attorney General reiterates and incorporates by reference the same objection set forth to Question No. 2, above. Without waiving such objection, the Attorney General states as follows: Not applicable, see the response to Question No. 2, above.

WITNESS/RESPONDENT RESPONSIBLE:
Counsel as to objection

QUESTION No. 4
Page 1 of 1

For each person identified in response to Interrogatory No. 2 above, please identify all proceedings in all jurisdictions in which the witness/person has offered evidence, including but not limited to, pre-filed testimony, sworn statements, and live testimony. For each response, please provide the following:

(a) The jurisdiction in which the testimony or statement was pre-filed, offered, given, or admitted into the record;
(b) The administrative agency and/or court in which the testimony or statement was pre-filed, offered, admitted, or given;
(c) The date(s) the testimony or statement was pre-filed, offered, admitted, or given;
(d) The identifying number for the case or proceeding in which the testimony or statement was pre-filed, offered, admitted, or given; and
(e) Whether the witness/person was cross-examined.

RESPONSE:

The Attorney General reiterates and incorporates by reference the same objection set forth to Question No. 2, above. Without waiving such objection, the Attorney General states as follows: Not applicable, see response to Question No. 2.

WITNESS/RESPONDENT RESPONSIBLE:
Counsel as to objection

QUESTION No. 5
Page 1 of 1

> Identify and provide all documents or other evidence that the Attorney General may seek to introduce as exhibits or for purposes of witness examination in the above-captioned matter.

RESPONSE:

Objection. The question seeks information which is or may be protected by work product and/or attorney-client privilege. Without waiving such objection, the Attorney General states that he has not yet identified any such documents, and that he will provide such information as soon as is practicable prior to the hearing in this matter to counsel for both the Company and the Commission Staff at a mutually agreed upon time and date.

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen / Richard A. Baudino / Glenn Watkins

QUESTION No. 6
Page 1 of 1

> Please provide copies of all pre-filed testimony provided by Messrs. Watkins, Kollen, and Baudino in any utility regulatory proceeding in any jurisdiction in the last five years.

RESPONSE:

Refer to Exhibit___(LK-1) attached to Mr. Kollen's Direct Testimony and Exhibit___ (RAB-1) attached to Mr. Baudino's Direct Testimony for a list of each witness' expert testimony, including the jurisdiction, docket number, and subject matter. See the Attachment titled "GAW Testimony List 2015–2020" for an index of Mr. Watkins' expert testimony over the last five years. The public version of their testimonies are available and can be readily accessed on the relevant federal and state commission websites.

EXPERT TESTIMONY
PROVIDED BY
GLENN A. WATKINS

YEAR	CASE NAME	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
2015	Exelon/PHI Acquisition	DE PSC	14-193	Merger/Acquisition
2015	Indianapolis Power & Light	Indiana OUCC	44576	Cost Allocations/Rate Design
2015	Choptank Electric Cooperative	MD OPC	9368	Cost Allocations/Rate Design
2015	PECO Energy Company-Service Expansion Tariff	PA PUC	R-2014-2451772	Mains Extension Policy
2015	PPL Electric Corporation	PA PUC	R-2015-2469275	Cost Allocations/Rate Design
2015	PECO Energy Company	PA PUC	R-2015-2468981	Cost Allocations/Rate Design
2015	Columbia Gas of Virginia	VA SCC	PUE-2014-00020	Rate Design-Customer Charges
2015	Credit Life/AH Rate Filing	VA SCC	INS-2015-00022	Market Structure and Performance
2015	NCCI (Workers Compensation Insurance)	VA SCC	INS-2015-00064	Workers Compensation Rates
2016	Chesapeake Utilities, Inc.	DE PSC	15-1734	Revenue Requirements/Cost Allocations/Rate Design
2016	Suez Water Company	DE PSC	16-0163	Revenue Requirements/Cost Allocations/Rate Design
2016	Delmarva Power & Light - Electric	DE PSC	16-0649	Revenue Requirements/Cost Allocations/Rate Design
2016	Delmarva Power & Light - Gas	DE PSC	16-0650	Revenue Requirements/Cost Allocations/Rate Design
2016	Northern Indiana Public Service Company	Indiana OUCC	Cause No. 44688	Cost Allocations/Rate Design
2016	Kansas Gas Service	KS CURB	16-KGSG-491-RTS	Cost Allocations/Rate Design
2016	Kentucky Utilities	Ky PSC	2016-00370	Cost Allocations/Rate Design
2016	Louisville Gas & Electric	Ky PSC	2016-00371	Cost Allocations/Rate Design
2016	Washington Suburban Sanitary Complaint Comission	MD OPC	Case No. 9391	Rate Structure
2016	Columbia Gas of Maryland	MD OPC	Case No. 9417	Cost Allocations/Rate Design/Main Line Extensions Policy
2016	Atlantic City Sewerage	NJ Rate Counsel	WR16100957	Cost of Capital
2016	UGI Utilities, Inc. - Gas Division	PA PUC	R-2015-2518438	Cost Allocations/Rate Design
2016	Peoples Service Expansion Tariff	PA PUC	R-2016-2542918	Mains Extension Policy
2016	Anthem/Cigna Merger	VA SCC	INS-2015-00154	Market Structure/Level of Competition
2016	NCCI (Workers Compensation Insurance)	Va SCC	INS-2016-00158	Workers Compensation Rates: Cost of Capital, IRR
2016	Washington Gas Light	VA SCC	PUE-2016-00001	Cost Allocations/Rate Design
2016	Cascade Natural Gas	WA UTC	UG-152286	Revenue Requirements
2016	Avista Utilities, Inc. (Gas & Electric)	WA UTC	UE-160228/UG-160229	Attrition
2017	Indiana Michigan Power Company	Indiana OUCC	Cause No. 44967	Cost Allocations/Rate Design
2017	Duke Energy Kentucky	Ky PSC	2017-00321	Cost Allocations/Rate Design
2017	Choptank Electric Cooperative	MD OPC	Case No. 9459	Rate Design
2017	UGI Penn Natural Gas	PA PUC	R-2016-2580030	Cost Allocations/Rate Design
2017	Pennsylvania-American Water	PA PUC	R-2017-259583	Cost of Capital
2017	Aqua-Limerick Valuations	PA PUC	A-2017-2605434	Discounted Cash Flow Valuation
2017	PAWC-McKeesport Valuations	PA PUC	A-2017-2606103	Discounted Cash Flow Valuation
2017	Virginia Natural Gas	VA SCC	PUE-2016-00143	Cost Allocations/Rate Design
2017	NCCI (Workers Compensation Insurance)	Va SCC	INS-2017-00059	Workers Compensation Rates: Cost of Capital, IRR
2017	Puget Sound Energy	WA UTC	UE-170033 & UG-170034	Cost Allocations/Rate Design
2018	Delmarva Power & Light - Electric	DE PSC	17-0977	Revenue Requirements and Rate Design
2018	Delmarva Power & Light - Gas	DE PSC	17-0978	Revenue Requirements and Rate Design
2018	Delmarva Power & Light Plug-In Vehicle Charging	DE PSC	17-1094	Ratepayer subsidies for Electric Vehicles
2018	Chesapeake Utilities, Inc. Natural Gas Expansion	DE PSC	17-1224	Mains Extension Policy
2018	Indianapolis Power & Light	Indiana OUCC	Cause No. 45029	Cost Allocations/Rate Design
2018	Kansas Gas Service	KS CURB	18-KGSG-560-RTS	Cost Allocations/Rate Design
2018	Baltimore Gas & Electric Company	MD OPC	Case No. 9484	Cost Allocations/Rate Design
2018	Duquesne Light Company	PA PUC	R-2018-3000124	Cost Allocations/Rate Design/EV Subsidy/Microgrid
2018	PAWC-Sadsbury Valuations	PA PUC	A-2018-3002437	Discounted Cash Flow Valuation
2018	SUEZ Water Company-Mahoning Valuations	PA PUC	A-2018-3003519	Discounted Cash Flow Valuation
2018	Aqua Pennsylvania, Inc.	PA PUC	R-2018-3003558	Cost of Capital
2019	Chesapeake Utilities	DE PSC	19-0054	WNA Rider/Cost of Equity

EXPERT TESTIMONY
PROVIDED BY
GLENN A. WATKINS

YEAR	CASE NAME	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
2019	Northern Indiana Public Service Company	Indiana OUCC	Cause No. 45159	Cost Allocations/Rate Design
2019	Indiana Michigan Power Company	Indiana OUCC	Cause No. 45235	Cost Allocations/Rate Design
2019	Duke Energy Indiana	Indiana OUCC	Cause No. 45253	Cost Allocations/Rate Design
2019	Atmos Energy Kansas	KS CURB	19-ATMG-525-RTS	Cost Allocations/Rate Design
2019	Kentucky Utilities/Louisville Gas & Electric	Ky PSC	2018-00294	Cost Allocations/Rate Design
2019	Montana-Dakota Utilities	Montana Consumer Counsel	D2018.9.60	Cost Allocations/Rate Design
2019	Sierra Pacific Power Company	NV PUC	19-06002	Cost Allocations/Rate Design
2019	Peoples Natural Gas Company	PA PUC	R-2018-3006818	Cost Allocations/Rate Design/Negotiated Rates
2019	PAWC-Exeter Valuations	PA PUC	A-2018-3004933	Discounted Cash Flow Valuation
2019	Aqua-Cheltenham Valuations	PA PUC	A-2019-3008491	Discounted Cash Flow Valuation
2019	PAWC-Steelton Valuations	PA PUC	A-2019-3006880	Discounted Cash Flow Valuation
2019	Washington Gas Light	VA SCC	PUR-2018-00080	Cost Allocations/Rate Design
2019	Virginia-American Water Company	VA SCC	PUR-2018-00175	Cost Allocations/Rate Design
2019	Avista Remand (Customer Refunds)	WA UTC	UE-150204 & UG-150205	Distribution of Refund to Classes
2019	Avista Utilities, Inc. - Gas	WA UTC	UG-19-00335	Cost Allocations/Rate Design
2019	Puget Sound Energy-Electric	WA UTC	UE-19-00529	Cost Allocations/Rate Design
2019	Puget Sound Energy-Gas	WA UTC	UG-19-00530	Cost Allocations/Rate Design
2019	Duke Energy Kentucky	Ky PSC	2019-00271	Rate Design
2020	Aqua - East Norriton Valuations	PA PUC	2019-3009052	Discounted Cash Flow Valuation

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen / Richard A. Baudino / Glenn Watkins

QUESTION No. 7

> Please provide copies of any and all documents, analysis, summaries, white papers, work papers, spreadsheets (electronic versions with cells intact), including drafts thereof, as well as any underlying supporting materials created by Messrs. Watkins, Kollen, and Baudino as part of their evaluation of the Company's Application or used in the creation of Messrs. Watkins, Kollen, and Baudino's testimony.

RESPONSE:

Mr. Kollen's electronic workpapers were filed in conjunction with his Direct Testimony. In addition to those workpapers, Mr. Kollen downloaded and sorted certain EIA Form 860 information in an electronic spreadsheet, a copy of which he has attached to this response.

Refer to the attached work papers for Mr. Baudino.

Please note that the Value Line reports relied upon by Mr. Baudino are protected by copyright and are available through a subscription to The Value Line Investment Survey. The Office of the Attorney General will also make these reports available for inspection at its offices at a mutually convenient time.

The materials cited in footnote numbers 10 and 11 from *A Random Walk Down Wall Street* and *Cost of Capital* are also protected by copyright and may not be copied. The Office of the Attorney General will also make these excerpts available for inspection at its offices at a mutually convenient time.

The material cited in footnotes 7 and 8 from *New Regulatory Finance* by Dr. Morin is copyright protected and may not be copied. Duke Energy Kentucky already has access to this book since Dr. Morin is a witness for the Company.

The material from Duff and Phelps Cost of Capital Navigator used in Mr. Baudino's Exhibit No.___(RAB-6) are also protected by copyright and may not be copied. The Office of the Attorney General will also make these materials available for inspection at its offices at a mutually convenient time. In preparing these responses, it was discovered that the source citation for the materials in Exhibit No.___(RAB-6) were inadvertently omitted. The reference to the sources is as follows:

Duff and Phelps Cost of Capital Navigator,
2019 Cost of Capital: Annual U.S. Guidance and Examples, Chapter 2, Exhibit 2.3, Chapter 3, pages 45-47

The material from the *2017 SBBI Yearbook* cited in footnote 15 is protected by copyright and may not be copied. The Office of the Attorney General will also make this material available for inspection at its offices at a mutually convenient time.

Please see attached Watkins' Excel files:

Completed Construction Not Classified.xlsx
Customer Cost Analysis1.xlsx
Duke Classification of Dist. Conductors.xlsx
Duke Cust Cost.xlsx
Meters Sorted per AG DR 1-78.xlsx

Corporate Bond Yield Averages

	AV. CORP.	CORPORATE BY RATINGS Aaa	Aa	A	Baa	CORPORATE BY GROUPS P.U.	IND.	R.R.
2002								
Jan.	7.38	6.55	7.03	7.50	7.87	7.69	7.07	---
Feb.	7.32	6.51	6.95	7.37	7.89	7.62	7.02	---
Mar.	7.57	6.81	7.22	7.62	8.11	7.83	7.30	---
Apr.	7.49	6.76	7.16	7.49	8.04	7.74	7.23	---
May	7.49	6.75	7.20	7.43	8.09	7.76	7.22	---
June	7.36	6.64	7.08	7.25	7.96	7.67	7.06	---
July	7.27	6.53	6.98	7.14	7.90	7.54	6.99	---
Aug.	7.06	6.37	6.84	6.95	7.58	7.34	6.77	---
Sep.	6.87	6.15	6.63	6.76	7.40	7.23	6.51	---
Oct.	7.08	6.33	6.74	6.95	7.74	7.43	6.72	---
Nov.	7.01	6.31	6.71	6.89	7.62	7.31	6.70	---
Dec.	6.90	6.21	6.63	6.80	7.45	7.20	6.59	---
2003								
Jan.	6.84	6.17	6.59	6.76	7.35	7.13	6.54	----
Feb.	6.62	5.95	6.34	6.63	7.06	6.92	6.31	----
Mar.	6.53	5.89	6.28	6.54	6.95	6.80	6.26	----
Apr.	6.44	5.74	6.22	6.45	6.85	6.68	6.18	----
May	6.02	5.22	5.85	6.08	6.38	6.35	5.70	----
June	5.85	4.97	5.72	5.92	6.19	6.21	5.49	----
July	6.26	5.49	6.07	6.34	6.62	6.54	5.98	----
Aug.	6.57	5.87	6.31	6.63	7.01	6.78	6.35	----
Sep.	6.37	5.72	6.13	6.42	6.79	6.58	6.16	----
Oct.	6.32	5.70	6.11	6.33	6.73	6.50	6.14	----
Nov.	6.27	5.65	6.08	6.28	6.66	6.44	6.09	----
Dec.	6.20	5.65	6.02	6.19	6.60	6.36	6.04	----
2004								
Jan.	6.08	5.54	5.91	6.08	6.44	6.23	5.92	----
Feb.	6.00	5.50	5.87	6.04	6.27	6.17	5.83	----
Mar.	5.84	5.33	5.70	5.86	6.11	6.01	5.67	----
Apr.	6.22	5.73	6.10	6.25	6.46	6.38	6.05	----
May.	6.51	6.04	6.40	6.54	6.75	6.68	6.34	----
June	6.42	6.01	6.21	6.42	6.78	6.53	6.31	----
July	6.24	5.82	6.02	6.23	6.62	6.34	6.13	----
Aug.	6.08	5.65	5.87	6.08	6.48	6.18	5.98	----
Sep.	5.91	5.46	5.73	5.91	6.27	6.01	5.81	----
Oct.	5.87	5.47	5.69	5.86	6.21	5.95	5.78	----
Nov.	5.89	5.52	5.72	5.88	6.21	5.97	5.80	----
Dec.	5.84	5.47	5.69	5.82	6.15	5.93	5.75	----
2005								
Jan.	5.72	5.36	5.58	5.68	6.02	5.80	5.63	----
Feb.	5.55	5.20	5.44	5.51	5.82	5.64	5.45	----
Mar.	5.77	5.40	5.64	5.73	6.06	5.86	5.67	----
Apr.	5.65	5.33	5.44	5.58	6.05	5.72	5.58	----
May	5.54	5.15	5.29	5.49	6.01	5.60	5.48	----
June	5.35	4.96	5.02	5.33	5.86	5.39	5.31	----
July	5.46	5.06	5.14	5.44	5.95	5.50	5.41	----
Aug.	5.49	5.09	5.20	5.48	5.96	5.51	5.46	----
Sept.	5.53	5.13	5.24	5.50	6.03	5.54	5.51	----
Oct.	5.77	5.34	5.46	5.75	6.29	5.79	5.74	----
Nov.	5.86	5.42	5.55	5.83	6.39	5.88	5.83	----
Dec.	5.81	5.38	5.51	5.84	6.33	5.83	5.80	----
2006								
Jan.	5.75	5.29	5.45	5.79	6.24	5.77	5.73	----
Feb.	5.80	5.35	5.51	5.85	6.27	5.83	5.78	----
Mar.	5.95	5.52	5.67	5.98	6.41	5.98	5.92	----
Apr.	6.26	5.84	6.00	6.27	6.68	6.28	6.23	----
May	6.36	5.95	6.13	6.40	6.75	6.39	6.33	----
June	6.35	5.89	6.11	6.39	6.78	6.39	6.31	----
July	6.33	5.85	6.08	6.36	6.76	6.37	6.28	----
Aug.	6.16	5.68	5.91	6.19	6.59	6.20	6.11	----
Sep.	5.98	5.51	5.75	5.98	6.43	6.03	5.94	----
Oct.	5.97	5.51	5.74	5.94	6.42	6.01	5.93	----
Nov.	5.78	5.33	5.57	5.76	6.20	5.82	5.73	----
Dec.	5.79	5.29	5.58	5.78	6.22	5.83	5.74	----
2007								
Jan.	5.92	5.40	5.75	5.93	6.34	5.96	5.88	----
Feb.	5.88	5.39	5.72	5.88	6.28	5.91	5.85	----
Mar.	5.84	5.30	5.66	5.84	6.27	5.87	5.80	----
Apr.	5.99	5.47	5.83	5.99	6.39	6.01	5.96	----
May	6.00	5.47	5.85	6.01	6.39	6.03	5.97	----
June	6.32	5.79	6.17	6.33	6.70	6.34	6.29	----
July	6.26	5.73	6.09	6.30	6.65	6.28	6.24	----
Aug.	6.26	5.79	6.06	6.29	6.65	6.28	6.23	----

	PUBLIC UTILITY BONDS Aaa	Aa	A	Baa
2002				
Jan.	----	7.28	7.66	8.13
Feb.	----	7.14	7.54	8.18
Mar.	----	7.42	7.76	8.32
Apr.	----	7.38	7.57	8.26
May	----	7.43	7.52	8.33
June	----	7.33	7.42	8.26
July	----	7.22	7.31	8.07
Aug.	----	7.10	7.17	7.74
Sep.	----	6.98	7.08	7.62
Oct.	----	7.07	7.23	8.00
Nov.	----	7.03	7.14	7.76
Dec.	----	6.94	7.07	7.61
2003				
Jan.	----	6.87	7.06	7.47
Feb.	----	6.66	6.93	7.17
Mar.	----	6.56	6.79	7.05
Apr.	----	6.47	6.64	6.94
May	----	6.20	6.36	6.47
June	----	6.12	6.21	6.30
July	----	6.37	6.57	6.67
Aug.	----	6.48	6.78	7.08
Sep.	----	6.30	6.56	6.87
Oct.	----	6.28	6.43	6.79
Nov.	----	6.26	6.37	6.69
Dec.	----	6.18	6.27	6.61
2004				
Jan.	----	6.06	6.15	6.47
Feb.	----	6.10	6.15	6.28
Mar.	----	5.93	5.97	6.12
Apr.	----	6.33	6.35	6.46
May.	----	6.66	6.62	6.75
June	----	6.30	6.46	6.84
July	----	6.09	6.27	6.67
Aug.	----	5.95	6.14	6.45
Sep.	----	5.79	5.98	6.27
Oct.	----	5.74	5.94	6.17
Nov.	----	5.79	5.97	6.16
Dec.	----	5.78	5.92	6.10
2005				
Jan.	----	5.68	5.78	5.95
Feb.	----	5.55	5.61	5.76
Mar.	----	5.76	5.83	6.01
Apr.	----	5.56	5.64	5.95
May	----	5.39	5.53	5.88
June	----	5.05	5.40	5.70
July	----	5.18	5.51	5.81
Aug.	----	5.23	5.50	5.80
Sept.	----	5.27	5.52	5.83
Oct.	----	5.50	5.79	6.08
Nov.	----	5.59	5.88	6.19
Dec.	----	5.55	5.80	6.14
2006				
Jan.	----	5.50	5.75	6.06
Feb.	----	5.55	5.82	6.11
Mar.	----	5.71	5.98	6.26
Apr.	----	6.02	6.29	6.54
May	----	6.16	6.42	6.59
June	----	6.16	6.40	6.61
July	----	6.13	6.37	6.61
Aug.	----	5.97	6.20	6.43
Sep.	----	5.81	6.00	6.26
Oct.	----	5.80	5.98	6.24
Nov.	----	5.61	5.80	6.04
Dec.	----	5.62	5.81	6.05
2007				
Jan.	----	5.78	5.96	6.16
Feb.	----	5.73	5.90	6.10
Mar.	----	5.66	5.85	6.10
Apr.	----	5.83	5.97	6.24
May	----	5.86	5.99	6.23
June	----	6.18	6.30	6.54
July	----	6.11	6.25	6.49
Aug.	----	6.11	6.24	6.51

	INDUSTRIAL BONDS Aaa	Aa	A	Baa
2002				
Jan.	6.55	6.78	7.35	7.60
Feb.	6.51	6.76	7.20	7.59
Mar.	6.81	7.02	7.47	7.89
Apr.	6.76	6.93	7.40	7.81
May	6.75	6.95	7.33	7.84
June	6.64	6.83	7.09	7.67
July	6.53	6.74	6.97	7.71
Aug.	6.37	6.57	6.73	7.42
Sep.	6.15	6.27	6.43	7.17
Oct.	6.33	6.40	6.67	7.48
Nov.	6.31	6.39	6.63	7.47
Dec.	6.21	6.32	6.53	7.28
2003				
Jan.	6.17	6.30	6.46	7.23
Feb.	5.95	6.02	6.33	6.94
Mar.	5.89	6.04	6.30	6.84
Apr.	5.74	5.97	6.26	6.76
May	5.22	5.48	5.79	6.29
June	4.97	5.31	5.62	6.07
July	5.49	5.77	6.11	6.56
Aug.	5.87	6.13	6.48	6.92
Sep.	5.72	5.95	6.27	6.71
Oct.	5.70	5.94	6.23	6.67
Nov.	5.65	5.91	6.18	6.63
Dec.	5.62	5.85	6.11	6.58
2004				
Jan.	5.54	5.74	6.02	6.40
Feb.	5.50	5.65	5.93	6.24
Mar.	5.33	5.48	5.75	6.10
Apr.	5.73	5.85	6.15	6.45
May.	6.04	6.13	6.45	6.73
June	6.01	6.12	6.37	6.72
July	5.82	5.94	6.18	6.57
Aug.	5.65	5.79	6.02	6.47
Sep.	5.46	5.67	5.84	6.27
Oct.	5.47	5.63	5.78	6.24
Nov.	5.52	5.65	5.78	6.25
Dec.	5.47	5.60	5.72	6.20
2005				
Jan.	5.36	5.48	5.58	6.08
Feb.	5.20	5.32	5.40	5.87
Mar.	5.40	5.53	5.63	6.11
Apr.	5.33	5.31	5.52	6.15
May	5.15	5.18	5.45	6.13
June	4.96	4.99	5.26	6.01
July	5.06	5.10	5.37	6.10
Aug.	5.09	5.16	5.45	6.12
Sept.	5.13	5.21	5.47	6.22
Oct.	5.34	5.42	5.70	6.49
Nov.	5.42	5.52	5.78	6.59
Dec.	5.38	5.45	5.88	6.51
2006				
Jan.	5.29	5.39	5.83	6.41
Feb.	5.35	5.46	5.87	6.43
Mar.	5.52	5.64	5.96	6.55
Apr.	5.84	5.98	6.26	6.82
May	5.95	6.10	6.37	6.90
June	5.89	6.05	6.36	6.94
July	5.85	6.02	6.35	6.91
Aug.	5.68	5.85	6.18	6.74
Sep.	5.51	5.68	5.95	6.59
Oct.	5.51	5.68	5.90	6.60
Nov.	5.33	5.52	5.72	6.36
Dec.	5.29	5.53	5.75	6.38
2007				
Jan.	5.40	5.71	5.91	6.52
Feb.	5.39	5.70	5.86	6.44
Mar.	5.30	5.66	5.83	6.43
Apr.	5.47	5.82	6.00	6.54
May	5.47	5.84	6.04	6.54
June	5.79	6.15	6.36	6.84
July	5.73	6.07	6.34	6.81
Aug.	5.79	6.01	6.35	6.79

	RAILROAD BONDS Aaa	Aa	A	Baa
2002				
Jan.	----	----	----	----
Feb.	----	----	----	----
Mar.	----	----	----	----
Apr.	----	----	----	----
May	----	----	----	----
June	----	----	----	----
July	----	----	----	----
Aug.	----	----	----	----
Sep.	----	----	----	----
Oct.	----	----	----	----
Nov.	----	----	----	----
Dec.	----	----	----	----
2003				
Jan.	----	----	----	----
Feb.	----	----	----	----
Mar.	----	----	----	----
Apr.	----	----	----	----
May	----	----	----	----
June	----	----	----	----
July	----	----	----	----
Aug.	----	----	----	----
Sep.	----	----	----	----
Oct.	----	----	----	----
Nov.	----	----	----	----
Dec.	----	----	----	----
2004				
Jan.	----	----	----	----
Feb.	----	----	----	----
Mar.	----	----	----	----
Apr.	----	----	----	----
May.	----	----	----	----
June	----	----	----	----
July	----	----	----	----
Aug.	----	----	----	----
Sep.	----	----	----	----
Oct.	----	----	----	----
Nov.	----	----	----	----
Dec.	----	----	----	----
2005				
Jan.	----	----	----	----
Feb.	----	----	----	----
Mar.	----	----	----	----
Apr.	----	----	----	----
May	----	----	----	----
June	----	----	----	----
July	----	----	----	----
Aug.	----	----	----	----
Sept.	----	----	----	----
Oct.	----	----	----	----
Nov.	----	----	----	----
Dec.	----	----	----	----
2006				
Jan.	----	----	----	----
Feb.	----	----	----	----
Mar.	----	----	----	----
Apr.	----	----	----	----
May	----	----	----	----
June	----	----	----	----
July	----	----	----	----
Aug.	----	----	----	----
Sep.	----	----	----	----
Oct.	----	----	----	----
Nov.	----	----	----	----
Dec.	----	----	----	----
2007				
Jan.	----	----	----	----
Feb.	----	----	----	----
Mar.	----	----	----	----
Apr.	----	----	----	----
May	----	----	----	----
June	----	----	----	----
July	----	----	----	----
Aug.	----	----	----	----

Notes: Moody's® Long-Term Corporate Bond Yield Averages have been published daily since 1929. They are derived from pricing data on a regularly -replenished population of nearly 75 seasoned corporate bonds in the US market, each with current outstandings over $100 million. The bonds have maturities as close as possi ble to 30 years; they are dropped from the list if their remaining life falls below 20 years, if their ratings change. Bonds with deep discounts or steep premiums to par are generally excluded. All y ields are yield-to-maturity calculated on a semi-annual basis. Each observation is an unweighted average, with Average Corporate Yields representing the unweighted average of the corresponding Av erage Industrial and Average Public Utility observations. Because of the dearth of **Aaa** -rated railroad term bond issues, Moody's® **Aaa** railroad bond yield average was discontinued as of December 18, 1967. Moody's ® **Aaa** public utility average suspended from Jan. 1984 thru Sept. 1984. Oct. 1984 figure for last 14 business days only. The Railroad Bond Averages were discontinued as of July 17, 1989 because of insufficient frequently tradable bonds. The July figures were based on 8 business days.

Because of the dearth of Aaa rated public utility bond issues, Moody's Aaa public utility bond yield average was discontinued a s of December 10, 2001.

Note: October 2002 figures have been adjusted.

Note: January 2003 figures have been adjusted.

Corporate Bond Yield Averages

	AV.	CORPORATE BY RATINGS				CORPORATE BY GROUPS				PUBLIC UTILITY BONDS					INDUSTRIAL BONDS					RAILROAD BONDS			
	CORP.	Aaa	Aa	A	Baa	P.U.	IND.	R.R.		Aaa	Aa	A	Baa		Aaa	Aa	A	Baa		Aaa	Aa	A	Baa
2006																							
Jan.	5.75	5.29	5.45	5.79	6.24	5.77	5.73	----	Jan.	----	5.50	5.75	6.06	Jan.	5.29	5.39	5.83	6.41	Jan.	----	----	----	----
Feb.	5.80	5.35	5.51	5.85	6.27	5.83	5.78	----	Feb.	----	5.55	5.82	6.11	Feb.	5.35	5.46	5.87	6.43	Feb.	----	----	----	----
Mar.	5.95	5.52	5.67	5.98	6.41	5.98	5.92	----	Mar.	----	5.71	5.98	6.26	Mar.	5.52	5.64	5.96	6.55	Mar.	----	----	----	----
Apr.	6.26	5.84	6.00	6.27	6.68	6.28	6.23	----	Apr.	----	6.02	6.29	6.54	Apr.	5.84	5.98	6.26	6.82	Apr.	----	----	----	----
May	6.36	5.95	6.13	6.40	6.75	6.39	6.33	----	May	----	6.16	6.42	6.59	May	5.95	6.10	6.37	6.90	May	----	----	----	----
June	6.35	5.89	6.11	6.39	6.78	6.39	6.31	----	June	----	6.16	6.40	6.61	June	5.89	6.05	6.36	6.94	June	----	----	----	----
July	6.33	5.85	6.08	6.36	6.76	6.37	6.28	----	July	----	6.13	6.37	6.61	July	5.85	6.02	6.35	6.91	July	----	----	----	----
Aug.	6.16	5.68	5.91	6.19	6.59	6.20	6.11	----	Aug.	----	5.97	6.20	6.43	Aug.	5.68	5.85	6.18	6.74	Aug.	----	----	----	----
Sept.	5.98	5.51	5.75	5.98	6.43	6.03	5.94	----	Sept.	----	5.81	6.00	6.26	Sept.	5.51	5.68	5.95	6.59	Sept.	----	----	----	----
Oct.	5.97	5.51	5.74	5.94	6.42	6.01	5.93	----	Oct.	----	5.80	5.98	6.24	Oct.	5.51	5.68	5.90	6.60	Oct.	----	----	----	----
Nov.	5.78	5.33	5.57	5.76	6.20	5.82	5.73	----	Nov.	----	5.61	5.80	6.04	Nov.	5.33	5.52	5.72	6.36	Nov.	----	----	----	----
Dec.	5.79	5.29	5.58	5.78	6.22	5.83	5.74	----	Dec.	----	5.62	5.81	6.05	Dec.	5.29	5.53	5.75	6.38	Dec.	----	----	----	----
2007																							
Jan.	5.92	5.40	5.75	5.93	6.34	5.96	5.88	----	Jan.	----	5.78	5.96	6.16	Jan.	5.40	5.71	5.91	6.52	Jan.	----	----	----	----
Feb.	5.88	5.39	5.72	5.88	6.28	5.91	5.85	----	Feb.	----	5.73	5.90	6.10	Feb.	5.39	5.70	5.86	6.44	Feb.	----	----	----	----
Mar.	5.84	5.30	5.66	5.84	6.27	5.87	5.80	----	Mar.	----	5.66	5.85	6.10	Mar.	5.30	5.66	5.83	6.43	Mar.	----	----	----	----
Apr.	5.99	5.47	5.83	5.99	6.39	6.01	5.96	----	Apr.	----	5.83	5.97	6.24	Apr.	5.47	5.82	6.00	6.54	Apr.	----	----	----	----
May	6.00	5.47	5.85	6.01	6.39	6.03	5.97	----	May	----	5.86	5.99	6.23	May	5.47	5.84	6.04	6.54	May	----	----	----	----
June	6.32	5.79	6.17	6.33	6.70	6.34	6.29	----	June	----	6.18	6.30	6.54	June	5.79	6.15	6.36	6.84	June	----	----	----	----
July	6.26	5.73	6.09	6.30	6.65	6.28	6.24	----	July	----	6.11	6.25	6.49	July	5.73	6.07	6.34	6.81	July	----	----	----	----
Aug.	6.26	5.79	6.06	6.29	6.65	6.28	6.23	----	Aug.	----	6.11	6.24	6.51	Aug.	5.79	6.01	6.35	6.79	Aug.	----	----	----	----
Sept.	6.21	5.74	6.02	6.23	6.59	6.24	6.17	----	Sept.	----	6.10	6.18	6.45	Sept.	5.74	5.93	6.28	6.73	Sept.	----	----	----	----
Oct.	6.12	5.66	5.94	6.13	6.48	6.17	6.06	----	Oct.	----	6.04	6.11	6.36	Oct.	5.66	5.84	6.14	6.60	Oct.	----	----	----	----
Nov.	5.97	5.44	5.78	5.97	6.40	6.04	5.90	----	Nov.	----	5.87	5.97	6.27	Nov.	5.44	5.67	5.97	6.51	Nov.	----	----	----	----
Dec.	6.15	5.49	5.91	6.19	6.65	6.23	6.07	----	Dec.	----	6.03	6.16	6.51	Dec.	5.49	5.78	6.22	6.78	Dec.	----	----	----	----
2008																							
Jan.	6.02	5.33	5.78	6.06	6.54	6.08	5.96	----	Jan.	----	5.87	6.02	6.35	Jan.	5.33	5.68	6.10	6.73	Jan.	----	----	----	----
Feb.	6.24	5.53	5.97	6.26	6.82	6.28	6.19	----	Feb.	----	6.04	6.21	6.60	Feb.	5.53	5.90	6.30	7.04	Feb.	----	----	----	----
Mar.	6.24	5.51	5.90	6.24	6.89	6.29	6.17	----	Mar.	----	5.99	6.21	6.68	Mar.	5.51	5.80	6.27	7.10	Mar.	----	----	----	----
Apr.	6.29	5.55	5.93	6.30	6.97	6.36	6.21	----	Apr.	----	5.99	6.29	6.81	Apr.	5.55	5.86	6.31	7.12	Apr.	----	----	----	----
May	6.30	5.57	6.00	6.30	6.92	6.38	6.22	----	May	----	6.07	6.27	6.79	May	5.57	5.93	6.33	7.05	May	----	----	----	----
June	6.42	5.68	6.11	6.43	7.07	6.50	6.35	----	June	----	6.19	6.38	6.93	June	5.68	6.02	6.48	7.22	June	----	----	----	----
July	6.44	5.67	6.05	6.47	7.16	6.50	6.38	----	July	----	6.13	6.40	6.97	July	5.67	5.97	6.54	7.35	July	----	----	----	----
Aug.	6.42	5.64	6.01	6.46	7.15	6.48	6.35	----	Aug.	----	6.09	6.37	6.98	Aug.	5.64	5.92	6.55	7.31	Aug.	----	----	----	----
Sept.	6.50	5.65	6.03	6.55	7.31	6.59	6.41	----	Sept.	----	6.13	6.49	7.15	Sept.	5.65	5.93	6.60	7.47	Sept.	----	----	----	----
Oct.	7.56	6.28	6.79	7.58	8.88	7.70	7.42	----	Oct.	----	6.95	7.56	8.58	Oct.	6.28	6.63	7.60	9.17	Oct.	----	----	----	----
Nov.	7.65	6.12	6.73	7.68	9.21	7.80	7.49	----	Nov.	----	6.83	7.60	8.98	Nov.	6.12	6.63	7.76	9.44	Nov.	----	----	----	----
Dec.	6.73	5.06	5.81	6.70	8.45	6.87	6.59	----	Dec.	----	5.93	6.54	8.13	Dec.	5.06	5.68	6.85	8.76	Dec.	----	----	----	----
2009																							
Jan.	6.59	5.05	5.84	6.46	8.14	6.77	6.41	----	Jan.	----	6.01	6.39	7.90	Jan.	5.05	5.67	6.52	8.39	Jan.	----	----	----	----
Feb.	6.64	5.27	6.02	6.47	8.08	6.72	6.56	----	Feb.	----	6.11	6.30	7.74	Feb.	5.27	5.93	6.62	8.42	Feb.	----	----	----	----
Mar.	6.84	5.50	6.11	6.66	8.42	6.85	6.83	----	Mar.	----	6.14	6.42	8.00	Mar.	5.50	6.07	6.90	8.84	Mar.	----	----	----	----
Apr.	6.85	5.39	6.17	6.70	8.39	6.90	6.79	----	Apr.	----	6.20	6.48	8.03	Apr.	5.39	6.14	6.90	8.74	Apr.	----	----	----	----
May	6.79	5.54	6.24	6.67	8.06	6.83	6.75	----	May	----	6.23	6.49	7.76	May	5.54	6.24	6.84	8.36	May	----	----	----	----
June	6.52	5.61	6.12	6.39	7.50	6.54	6.49	----	June	----	6.13	6.20	7.30	June	5.61	6.11	6.58	7.69	June	----	----	----	----
July	6.17	5.41	5.71	6.09	7.09	6.15	6.18	----	July	----	5.63	5.97	6.87	July	5.41	5.78	6.20	7.30	July	----	----	----	----
Aug.	5.83	5.26	5.45	5.78	6.58	5.80	5.86	----	Aug.	----	5.33	5.71	6.36	Aug.	5.26	5.56	5.84	6.79	Aug.	----	----	----	----
Sept.	5.61	5.13	5.21	5.56	6.31	5.60	5.62	----	Sept.	----	5.15	5.53	6.12	Sept.	5.13	5.27	5.58	6.50	Sept.	----	----	----	----
Oct.	5.63	5.15	5.24	5.57	6.29	5.64	5.61	----	Oct.	----	5.23	5.55	6.14	Oct.	5.15	5.25	5.59	6.44	Oct.	----	----	----	----
Nov.	5.68	5.19	5.29	5.64	6.32	5.71	5.64	----	Nov.	----	5.33	5.64	6.18	Nov.	5.19	5.26	5.64	6.46	Nov.	----	----	----	----
Dec.	5.78	5.26	5.44	5.77	6.37	5.86	5.71	----	Dec.	----	5.52	5.79	6.26	Dec.	5.26	5.36	5.74	6.47	Dec.	----	----	----	----
2010																							
Jan.	5.76	5.26	5.50	5.76	6.25	5.83	5.69	----	Jan.	----	5.55	5.77	6.16	Jan.	5.26	5.44	5.73	6.33	Jan.	----	----	----	----
Feb.	5.86	5.35	5.62	5.84	6.34	5.94	5.79	----	Feb.	----	5.69	5.87	6.25	Feb.	5.35	5.55	5.80	6.43	Feb.	----	----	----	----
Mar.	5.81	5.27	5.57	5.80	6.27	5.90	5.71	----	Mar.	----	5.64	5.84	6.22	Mar.	5.27	5.49	5.75	6.32	Mar.	----	----	----	----
Apr.	5.80	5.29	5.57	5.78	6.25	5.87	5.71	----	Apr.	----	5.62	5.81	6.19	Apr.	5.29	5.50	5.74	6.32	Apr.	----	----	----	----
May	5.52	4.96	5.25	5.49	6.05	5.59	5.44	----	May	----	5.29	5.50	5.97	May	4.96	5.19	5.47	6.13	May	----	----	----	----
June	5.52	4.88	5.16	5.44	6.23	5.62	5.42	----	June	----	5.22	5.46	6.18	June	4.88	5.11	5.42	6.28	June	----	----	----	----
July	5.32	4.72	4.96	5.25	6.01	5.41	5.23	----	July	----	4.99	5.26	5.98	July	4.72	4.92	5.23	6.04	July	----	----	----	----
Aug.	5.05	4.49	4.72	5.00	5.66	5.10	4.98	----	Aug.	----	4.75	5.01	5.55	Aug.	4.49	4.68	4.98	5.77	Aug.	----	----	----	----
Sept.	5.05	4.53	4.72	5.01	5.66	5.10	5.00	----	Sept.	----	4.74	5.01	5.53	Sept.	4.53	4.70	5.00	5.78	Sept.	----	----	----	----
Oct.	5.15	4.68	4.83	5.09	5.72	5.20	5.08	----	Oct.	----	4.89	5.10	5.62	Oct.	4.68	4.77	5.07	5.81	Oct.	----	----	----	----
Nov.	5.37	4.87	5.07	5.33	5.92	5.45	5.29	----	Nov.	----	5.12	5.37	5.85	Nov.	4.87	5.02	5.29	5.99	Nov.	----	----	----	----
Dec.	5.55	5.02	5.26	5.52	6.10	5.64	5.46	----	Dec.	----	5.32	5.56	6.04	Dec.	5.02	5.19	5.47	6.15	Dec.	----	----	----	----
2011																							
Jan.	5.56	5.04	5.26	5.53	6.09	5.64	5.46	----	Jan.	----	5.29	5.57	6.06	Jan.	5.04	5.22	5.48	6.11	Jan.	----	----	----	----
Feb.	5.66	5.22	5.37	5.64	6.15	5.73	5.58	----	Feb.	----	5.42	5.68	6.10	Feb.	5.22	5.31	5.59	6.19	Feb.	----	----	----	----
Mar.	5.55	5.13	5.28	5.52	6.03	5.62	5.48	----	Mar.	----	5.33	5.56	5.97	Mar.	5.13	5.22	5.48	6.09	Mar.	----	----	----	----
Apr.	5.56	5.16	5.29	5.52	6.02	5.62	5.49	----	Apr.	----	5.32	5.55	5.98	Apr.	5.16	5.25	5.48	6.06	Apr.	----	----	----	----
May	5.33	4.96	5.06	5.29	5.78	5.38	5.27	----	May	----	5.08	5.32	5.74	May	4.96	5.04	5.26	5.81	May	----	----	----	----
June	5.30	4.99	5.04	5.26	5.75	5.33	5.27	----	June	----	5.04	5.26	5.67	June	4.99	5.02	5.25	5.82	June	----	----	----	----
July	5.30	4.93	5.03	5.26	5.76	5.34	5.25	----	July	----	5.05	5.27	5.70	July	4.93	4.99	5.25	5.81	July	----	----	----	----
Aug.	4.79	4.37	4.47	4.74	5.36	4.78	4.79	----	Aug.	----	4.44	4.69	5.22	Aug.	4.37	4.50	4.79	5.49	Aug.	----	----	----	----
Sept.	4.60	4.09	4.23	4.54	5.27	4.61	4.58	----	Sept.	----	4.24	4.48	5.11	Sept.	4.09	4.21	4.59	5.42	Sept.	----	----	----	----
Oct.	4.60	3.98	4.16	4.54	5.37	4.66	4.54	----	Oct.	----	4.21	4.52	5.24	Oct.	3.98	4.11	4.56	5.50	Oct.	----	----	----	----
Nov.	4.39	3.87	3.97	4.34	5.14	4.37	4.41	----	Nov.	----	3.92	4.25	4.93	Nov.	3.87	4.01	4.43	5.34	Nov.	----	----	----	----
Dec.	4.47	3.93	4.03	4.40	5.25	4.47	4.47	----	Dec.	----	4.00	4.33	5.07	Dec.	3.93	4.06	4.46	5.43	Dec.	----	----	----	----

Notes: Moody's® Long-Term Corporate Bond Yield Averages have been published daily since 1929. They are derived from pricing data on a regularly-replenished population of nearly 75 seasoned corporate bonds in the US market, each with current outstandings over $100 million. The bonds have maturities as close as possible to 30 years; they are dropped from the list if their remaining life falls below 20 years, if their ratings change. Bonds with deep discounts or steep premiums to par are generally excluded. All yields are yield-to-maturity calculated on a semi-annual basis. Each observation is an unweighted average, with Average Corporate Yields representing the unweighted average of the corresponding Average Industrial and Average Public Utility observations. Because of the dearth of **Aaa** -rated railroad term bond issues, Moody's® **Aaa** railroad bond yield average was discontinued as of December 18, 1967. Moody's® **Aaa** public utility average suspended from Jan. 1984 thru Sept. 1984. Oct. 1984 figure for last 14 business days only. The Railroad Bond Averages were discontinued as of July 17, 1989 because of insufficient frequently tradable bonds. The July figures were based on 8 business days.
Because of the dearth of Aaa rated public utility bond issues, Moody's Aaa public utility bond yield average was discontinued as of December 10, 2001.

Corporate Bond Yield Averages

	AV. CORP.	Corporate by Ratings Aaa	Aa	A	Baa	Corporate by Groups P.U.	IND.	R.R.		Public Utility Bonds Aaa	Aa	A	Baa		Industrial Bonds Aaa	Aa	A	Baa		Railroad Bonds Aaa	Aa	A	Baa
2010																							
Jan.	5.76	5.26	5.50	5.76	6.25	5.83	5.69	----	Jan.	----	5.55	5.77	6.16	Jan.	5.26	5.44	5.73	6.33	Jan.	----	----	----	----
Feb.	5.86	5.35	5.62	5.84	6.34	5.94	5.79	----	Feb.	----	5.69	5.87	6.25	Feb.	5.35	5.55	5.80	6.43	Feb.	----	----	----	----
Mar.	5.81	5.27	5.57	5.80	6.27	5.90	5.71	----	Mar.	----	5.64	5.84	6.22	Mar.	5.27	5.49	5.75	6.32	Mar.	----	----	----	----
Apr.	5.80	5.29	5.57	5.78	6.25	5.87	5.71	----	Apr.	----	5.62	5.81	6.19	Apr.	5.29	5.50	5.74	6.32	Apr.	----	----	----	----
May	5.52	4.96	5.25	5.49	6.05	5.59	5.44	----	May	----	5.29	5.50	5.97	May	4.96	5.19	5.47	6.13	May	----	----	----	----
June	5.52	4.88	5.16	5.44	6.23	5.62	5.42	----	June	----	5.22	5.46	6.18	June	4.88	5.11	5.42	6.28	June	----	----	----	----
July	5.32	4.72	4.96	5.25	6.01	5.41	5.23	----	July	----	4.99	5.26	5.98	July	4.72	4.92	5.23	6.04	July	----	----	----	----
Aug.	5.05	4.49	4.72	5.00	5.66	5.10	4.98	----	Aug.	----	4.75	5.01	5.55	Aug.	4.49	4.68	4.98	5.77	Aug.	----	----	----	----
Sept.	5.05	4.53	4.72	5.01	5.66	5.10	5.00	----	Sept.	----	4.74	5.01	5.53	Sept.	4.53	4.70	5.00	5.78	Sept.	----	----	----	----
Oct.	5.15	4.68	4.83	5.09	5.72	5.20	5.08	----	Oct.	----	4.89	5.10	5.62	Oct.	4.68	4.77	5.07	5.81	Oct.	----	----	----	----
Nov.	5.37	4.87	5.07	5.33	5.92	5.45	5.29	----	Nov.	----	5.12	5.37	5.85	Nov.	4.87	5.02	5.29	5.99	Nov.	----	----	----	----
Dec.	5.55	5.02	5.26	5.52	6.10	5.64	5.46	----	Dec.	----	5.32	5.56	6.04	Dec.	5.02	5.19	5.47	6.15	Dec.	----	----	----	----
2011																							
Jan.	5.56	5.04	5.26	5.53	6.09	5.64	5.46	----	Jan.	----	5.29	5.57	6.06	Jan.	5.04	5.22	5.48	6.11	Jan.	----	----	----	----
Feb.	5.66	5.22	5.37	5.64	6.15	5.73	5.58	----	Feb.	----	5.42	5.68	6.10	Feb.	5.22	5.31	5.59	6.19	Feb.	----	----	----	----
Mar.	5.55	5.13	5.28	5.52	6.03	5.62	5.48	----	Mar.	----	5.33	5.56	5.97	Mar.	5.13	5.22	5.48	6.09	Mar.	----	----	----	----
Apr.	5.56	5.16	5.29	5.52	6.02	5.62	5.49	----	Apr.	----	5.32	5.55	5.98	Apr.	5.16	5.25	5.48	6.06	Apr.	----	----	----	----
May	5.33	4.96	5.06	5.29	5.78	5.38	5.27	----	May	----	5.08	5.32	5.74	May	4.96	5.04	5.26	5.81	May	----	----	----	----
June	5.30	4.99	5.04	5.26	5.75	5.33	5.27	----	June	----	5.04	5.26	5.67	June	4.99	5.02	5.25	5.82	June	----	----	----	----
July	5.30	4.93	5.03	5.26	5.76	5.34	5.25	----	July	----	5.05	5.27	5.70	July	4.93	4.99	5.25	5.81	July	----	----	----	----
Aug.	4.79	4.37	4.47	4.74	5.36	4.78	4.79	----	Aug.	----	4.44	4.69	5.22	Aug.	4.37	4.50	4.79	5.49	Aug.	----	----	----	----
Sept.	4.60	4.09	4.23	4.54	5.27	4.61	4.58	----	Sept.	----	4.24	4.48	5.11	Sept.	4.09	4.21	4.59	5.42	Sept.	----	----	----	----
Oct.	4.60	3.98	4.16	4.54	5.37	4.66	4.54	----	Oct.	----	4.21	4.52	5.24	Oct.	3.98	4.11	4.56	5.50	Oct.	----	----	----	----
Nov.	4.39	3.87	3.97	4.34	5.14	4.37	4.41	----	Nov.	----	3.92	4.25	4.93	Nov.	3.87	4.01	4.43	5.34	Nov.	----	----	----	----
Dec.	4.47	3.93	4.03	4.40	5.25	4.47	4.47	----	Dec.	----	4.00	4.33	5.07	Dec.	3.93	4.06	4.46	5.43	Dec.	----	----	----	----
2012																							
Jan.	4.45	3.85	4.01	4.39	5.23	4.48	4.41	----	Jan.	----	4.03	4.34	5.06	Jan.	3.85	3.98	4.43	5.39	Jan.	----	----	----	----
Feb.	4.42	3.85	3.99	4.39	5.14	4.47	4.37	----	Feb.	----	4.02	4.36	5.02	Feb.	3.85	3.96	4.41	5.26	Feb.	----	----	----	----
Mar.	4.54	3.99	4.14	4.51	5.23	4.59	4.50	----	Mar.	----	4.16	4.48	5.13	Mar.	3.99	4.12	4.53	5.33	Mar.	----	----	----	----
Apr.	4.49	3.96	4.08	4.44	5.19	4.53	4.44	----	Apr.	----	4.10	4.40	5.11	Apr.	3.96	4.06	4.48	5.27	Apr.	----	----	----	----
May	4.33	3.80	3.91	4.26	5.07	4.36	4.30	----	May	----	3.92	4.20	4.97	May	3.80	3.90	4.32	5.17	May	----	----	----	----
June	4.22	3.64	3.78	4.14	5.02	4.26	4.18	----	June	----	3.79	4.08	4.91	June	3.64	3.77	4.18	5.13	June	----	----	----	----
July	4.03	3.40	3.54	3.93	4.87	4.12	3.93	----	July	----	3.58	3.93	4.85	July	3.40	3.49	3.93	4.89	July	----	----	----	----
Aug.	4.09	3.48	3.61	3.99	4.91	4.18	3.99	----	Aug.	----	3.65	4.00	4.88	Aug.	3.48	3.57	3.98	4.93	Aug.	----	----	----	----
Sept.	4.09	3.49	3.68	4.01	4.84	4.17	4.00	----	Sept.	----	3.69	4.02	4.81	Sept.	3.49	3.66	4.00	4.87	Sept.	----	----	----	----
Oct.	3.97	3.47	3.63	3.90	4.58	4.05	3.89	----	Oct.	----	3.68	3.91	4.54	Oct.	3.47	3.58	3.89	4.62	Oct.	----	----	----	----
Nov.	3.92	3.50	3.57	3.87	4.51	3.95	3.88	----	Nov.	----	3.60	3.84	4.42	Nov.	3.50	3.54	3.89	4.60	Nov.	----	----	----	----
Dec.	4.05	3.65	3.70	3.98	4.63	4.10	3.99	----	Dec.	----	3.75	4.00	4.56	Dec.	3.65	3.65	3.96	4.70	Dec.	----	----	----	----
2013																							
Jan.	4.19	3.80	3.87	4.14	4.73	4.24	4.14	----	Jan.	----	3.90	4.15	4.66	Jan.	3.80	3.84	4.13	4.81	Jan.	----	----	----	----
Feb.	4.27	3.90	3.95	4.19	4.85	4.29	4.25	----	Feb.	----	3.95	4.18	4.74	Feb.	3.90	3.95	4.20	4.95	Feb.	----	----	----	----
Mar.	4.29	3.93	3.97	4.23	4.85	4.29	4.29	----	Mar.	----	3.95	4.20	4.72	Mar.	3.93	3.98	4.25	4.99	Mar.	----	----	----	----
Apr.	4.07	3.73	3.77	4.03	4.59	4.08	4.07	----	Apr.	----	3.74	4.00	4.49	Apr.	3.73	3.79	4.05	4.69	Apr.	----	----	----	----
May	4.23	3.89	3.94	4.19	4.73	4.24	4.22	----	May	----	3.91	4.17	4.65	May	3.89	3.97	4.20	4.80	May	----	----	----	----
June	4.63	4.27	4.32	4.56	5.19	4.63	4.63	----	June	----	4.27	4.53	5.08	June	4.27	4.36	4.58	5.29	June	----	----	----	----
July	4.76	4.34	4.46	4.69	5.32	4.78	4.74	----	July	----	4.44	4.68	5.21	July	4.34	4.47	4.69	5.43	July	----	----	----	----
Aug.	4.88	4.54	4.63	4.78	5.42	4.85	4.92	----	Aug.	----	4.53	4.73	5.28	Aug.	4.54	4.72	4.83	5.57	Aug.	----	----	----	----
Sept.	4.95	4.64	4.69	4.85	5.47	4.90	4.99	----	Sept.	----	4.58	4.80	5.31	Sept.	4.64	4.80	4.90	5.62	Sept.	----	----	----	----
Oct.	4.82	4.53	4.59	4.73	5.31	4.78	4.86	----	Oct.	----	4.48	4.70	5.17	Oct.	4.53	4.69	4.76	5.44	Oct.	----	----	----	----
Nov.	4.91	4.63	4.67	4.82	5.38	4.86	4.95	----	Nov.	----	4.56	4.77	5.24	Nov.	4.63	4.79	4.85	5.52	Nov.	----	----	----	----
Dec.	4.92	4.62	4.68	4.85	5.38	4.89	4.95	----	Dec.	----	4.59	4.81	5.25	Dec.	4.62	4.76	4.89	5.51	Dec.	----	----	----	----
2014																							
Jan.	4.76	4.49	4.53	4.69	5.19	4.72	4.78	----	Jan.	----	4.44	4.63	5.09	Jan.	4.49	4.62	4.74	5.29	Jan.	----	----	----	----
Feb.	4.68	4.45	4.46	4.60	5.10	4.64	4.71	----	Feb.	----	4.38	4.53	5.01	Feb.	4.45	4.54	4.66	5.19	Feb.	----	----	----	----
Mar.	4.65	4.38	4.44	4.56	5.06	4.63	4.65	----	Mar.	----	4.40	4.51	5.00	Mar.	4.38	4.49	4.60	5.13	Mar.	----	----	----	----
Apr.	4.52	4.24	4.33	4.45	4.90	4.52	4.51	----	Apr.	----	4.30	4.41	4.85	Apr.	4.24	4.36	4.48	4.96	Apr.	----	----	----	----
May	4.38	4.16	4.20	4.31	4.76	4.37	4.40	----	May	----	4.16	4.26	4.69	May	4.16	4.24	4.35	4.83	May	----	----	----	----
June	4.44	4.25	4.26	4.35	4.80	4.42	4.45	----	June	----	4.23	4.29	4.73	June	4.25	4.29	4.41	4.86	June	----	----	----	----
July	4.37	4.16	4.20	4.28	4.73	4.35	4.39	----	July	----	4.16	4.23	4.66	July	4.16	4.23	4.34	4.80	July	----	----	----	----
Aug.	4.29	4.08	4.10	4.20	4.69	4.29	4.30	----	Aug.	----	4.07	4.13	4.65	Aug.	4.08	4.13	4.26	4.72	Aug.	----	----	----	----
Sept.	4.39	4.11	4.19	4.30	4.80	4.40	4.37	----	Sept.	----	4.18	4.24	4.79	Sept.	4.11	4.19	4.35	4.82	Sept.	----	----	----	----
Oct.	4.22	3.92	3.99	4.13	4.69	4.24	4.20	----	Oct.	----	3.98	4.06	4.67	Oct.	3.92	4.00	4.20	4.70	Oct.	----	----	----	----
Nov.	4.28	3.92	4.04	4.18	4.79	4.29	4.26	----	Nov.	----	4.03	4.09	4.75	Nov.	3.92	4.04	4.27	4.82	Nov.	----	----	----	----
Dec.	4.17	3.79	3.89	4.05	4.74	4.18	4.15	----	Dec.	----	3.90	3.95	4.70	Dec.	3.79	3.89	4.15	4.77					
2015																							
Jan.	3.84	3.46	3.54	3.70	4.45	3.83	3.84	----	Jan.	----	3.52	3.58	4.39	Jan.	3.46	3.55	3.82	4.51	Jan.	----	----	----	----
Feb.	3.93	3.61	3.64	3.81	4.51	3.91	3.94	----	Feb.	----	3.62	3.67	4.44	Feb.	3.61	3.65	3.94	4.57	Feb.	----	----	----	----
Mar.	3.98	3.64	3.70	3.85	4.54	3.97	3.97	----	Mar.	----	3.67	3.74	4.51	Mar.	3.64	3.72	3.96	4.56	Mar.	----	----	----	----
Apr.	3.93	3.52	3.64	3.82	4.48	3.96	3.88	----	Apr.	----	3.63	3.75	4.51	Apr.	3.52	3.65	3.89	4.45	Apr.	----	----	----	----
May	4.35	3.98	4.07	4.24	4.89	4.38	4.31	----	May	----	4.05	4.17	4.91	May	3.98	4.09	4.30	4.86	May	----	----	----	----
June	4.56	4.19	4.27	4.45	5.13	4.60	4.52	----	June	----	4.29	4.39	5.13	June	4.19	4.25	4.51	5.12	June	----	----	----	----
July	4.57	4.15	4.25	4.44	5.20	4.63	4.51	----	July	----	4.27	4.40	5.22	July	4.15	4.22	4.49	5.18	July	----	----	----	----
Aug.	4.48	4.04	4.13	4.32	5.19	4.54	4.42	----	Aug.	----	4.13	4.25	5.23	Aug.	4.04	4.11	4.39	5.15	Aug.	----	----	----	----
Sept.	4.59	4.07	4.21	4.43	5.34	4.68	4.49	----	Sept.	----	4.25	4.39	5.42	Sept.	4.07	4.16	4.46	5.25	Sept.	----	----	----	----
Oct.	4.52	3.95	4.11	4.33	5.34	4.63	4.40	----	Oct.	----	4.13	4.29	5.47	Oct.	3.95	4.08	4.37	5.21	Oct.	----	----	----	----
Nov.	4.62	4.06	4.21	4.43	5.46	4.73	4.51	----	Nov.	----	4.22	4.40	5.57	Nov.	4.06	4.20	4.45	5.34	Nov.	----	----	----	----
Dec.	4.58	3.97	4.16	4.38	5.46	4.69	4.47	----	Dec.	----	4.16	4.35	5.55	Dec.	3.97	4.16	4.40	5.36	Dec.	----	----	----	----
2016																							
Jan.	4.56	4.00	4.12	4.35	5.45	4.62	4.50	----	Jan.	----	4.09	4.27	5.49	Jan.	4.00	4.16	4.42	5.40	Jan.	----	----	----	----
Feb.	4.44	3.96	3.98	4.22	5.34	4.44	4.43	----	Feb.	----	3.94	4.11	5.28	Feb.	3.96	4.02	4.33	5.39	Feb.	----	----	----	----
Mar.	4.33	3.82	3.91	4.16	5.13	4.40	4.25	----	Mar.	----	3.93	4.16	5.12	Mar.	3.82	3.89	4.16	5.14	Mar.	----	----	----	----
Apr.	4.09	3.62	3.71	3.98	4.79	4.16	4.01	----	Apr.	----	3.74	4.00	4.75	Apr.	3.62	3.67	3.95	4.82	Apr.	----	----	----	----
May	4.04	3.65	3.70	3.94	4.68	4.06	4.02	----	May	----	3.65	3.93	4.60	May	3.65	3.73	3.95	4.75	May	----	----	----	----
June	3.91	3.50	3.60	3.80	4.53	3.93	3.88	----	June	----	3.56	3.78	4.47	June	3.50	3.63	3.82	4.58	June	----	----	----	----
July	3.67	3.28	3.39	3.58	4.22	3.70	3.64	----	July	----	3.36	3.57	4.16	July	3.28	3.42	3.58	4.27	July	----	----	----	----
Aug.	3.70	3.32	3.42	3.60	4.24	3.73	3.66	----	Aug.	----	3.39	3.59	4.20	Aug.	3.32	3.45	3.61	4.27	Aug.	----	----	----	----
Sept.	3.78	3.41	3.50	3.68	4.31	3.80	3.75	----	Sept.	----	3.47	3.66	4.27	Sept.	3.41	3.53	3.69	4.35	Sept.	----	----	----	----
Oct.	3.87	3.51	3.61	3.78	4.38	3.90	3.84	----	Oct.	----	3.59	3.77	4.34	Oct.	3.51	3.63	3.79	4.40	Oct.	----	----	----	----
Nov.	4.20	3.86	3.94	4.11	4.71	4.21	4.19	----	Nov.	----	3.91	4.08	4.64	Nov.	3.86	3.97	4.14	4.77	Nov.	----	----	----	----
Dec.	4.36	4.06	4.12	4.28	4.83	4.39	4.33	----	Dec.	----	4.11	4.27	4.79	Dec.	4.06	4.13	4.29	4.85	Dec.	----	----	----	----
2017																							
Jan.	4.22	3.92	3.98	4.16	4.66	4.24	4.20	----	Jan.	----	3.96	4.14	4.62	Jan.	3.92	4.00	4.17	4.70	Jan.	----	----	----	----

Notes: Moody's® Long-Term Corporate Bond Yield Averages have been published daily since 1929. They are derived from pricing data on a regularly-replenished population of nearly 75 seasoned corporate bonds in the US market, each with current outstandings over $100 million. The bonds have maturities as close as possible to 30 years; they are dropped from the list if their remaining life falls below 20 years, if their ratings change. Bonds with deep discounts or steep premiums to par are generally excluded. All yields are yield-to-maturity calculated on a semi-annual basis. Each observation is an unweighted average, with Average Corporate Yields representing the unweighted average of the corresponding Average Industrial and Average Public Utility observations. Because of the dearth of **Aaa** -rated railroad term bond issues, Moody's® **Aaa** railroad bond yield average was discontinued as of December 18, 1967. Moody's® **Aaa** public utility average suspended from Jan. 1984 thru Sept. 1984. Oct. 1984 figure for last 14 business days only. The Railroad Bond Averages were discontinued as of July 17, 1989 because of insufficient frequently tradable bonds. The July figures were based on 8 business days.

Because of the dearth of Aaa rated public utility bond issues, Moody's Aaa public utility bond yield average was discontinued as of December 10, 2001.

Corporate Bond Yield Averages

	AV. CORP.	CORPORATE BY RATINGS Aaa	Aa	A	Baa	CORPORATE BY GROUPS P.U.	IND.	R.R.		PUBLIC UTILITY BONDS Aaa	Aa	A	Baa		INDUSTRIAL BONDS Aaa	Aa	A	Baa		RAILROAD BONDS Aaa	Aa	A	Baa
2009																							
Feb.	6.64	5.27	6.02	6.47	8.08	6.72	6.56	----	Feb.	----	6.11	6.30	7.74	Feb.	5.27	5.93	6.62	8.42	Feb.	----	----	----	----
Mar.	6.84	5.50	6.11	6.66	8.42	6.85	6.83	----	Mar.	----	6.14	6.42	8.00	Mar.	5.50	6.07	6.90	8.84	Mar.	----	----	----	----
Apr.	6.85	5.39	6.17	6.70	8.39	6.90	6.79	----	Apr.	----	6.20	6.48	8.03	Apr.	5.39	6.14	6.90	8.74	Apr.	----	----	----	----
May	6.79	5.54	6.24	6.67	8.06	6.83	6.75	----	May	----	6.23	6.49	7.76	May	5.54	6.24	6.84	8.36	May	----	----	----	----
June	6.52	5.61	6.12	6.39	7.50	6.54	6.49	----	June	----	6.13	6.20	7.30	June	5.61	6.11	6.58	7.69	June	----	----	----	----
July	6.17	5.41	5.71	6.09	7.09	6.15	6.18	----	July	----	5.63	5.97	6.87	July	5.41	5.78	6.20	7.30	July	----	----	----	----
Aug.	5.83	5.26	5.45	5.78	6.58	5.80	5.86	----	Aug.	----	5.33	5.71	6.36	Aug.	5.26	5.56	5.84	6.79	Aug.	----	----	----	----
Sept.	5.61	5.13	5.21	5.56	6.31	5.60	5.62	----	Sept.	----	5.15	5.53	6.12	Sept.	5.13	5.27	5.58	6.50	Sept.	----	----	----	----
Oct.	5.63	5.15	5.24	5.57	6.29	5.64	5.61	----	Oct.	----	5.23	5.55	6.14	Oct.	5.15	5.25	5.59	6.44	Oct.	----	----	----	----
Nov.	5.68	5.19	5.29	5.64	6.32	5.71	5.64	----	Nov.	----	5.33	5.64	6.18	Nov.	5.19	5.26	5.64	6.46	Nov.	----	----	----	----
Dec.	5.78	5.26	5.44	5.77	6.37	5.86	5.71	----	Dec.	----	5.52	5.79	6.26	Dec.	5.26	5.36	5.74	6.47	Dec.	----	----	----	----
2010																							
Jan.	5.76	5.26	5.50	5.76	6.25	5.83	5.69	----	Jan.	----	5.55	5.77	6.16	Jan.	5.26	5.44	5.73	6.33	Jan.	----	----	----	----
Feb.	5.86	5.35	5.62	5.84	6.34	5.94	5.79	----	Feb.	----	5.69	5.87	6.25	Feb.	5.35	5.55	5.80	6.43	Feb.	----	----	----	----
Mar.	5.81	5.27	5.57	5.80	6.27	5.90	5.71	----	Mar.	----	5.64	5.84	6.22	Mar.	5.27	5.49	5.75	6.32	Mar.	----	----	----	----
Apr.	5.80	5.29	5.57	5.78	6.25	5.87	5.71	----	Apr.	----	5.62	5.81	6.19	Apr.	5.29	5.50	5.74	6.32	Apr.	----	----	----	----
May	5.52	4.96	5.25	5.49	6.05	5.59	5.44	----	May	----	5.29	5.50	5.97	May	4.96	5.19	5.47	6.13	May	----	----	----	----
June	5.52	4.88	5.16	5.44	6.23	5.62	5.42	----	June	----	5.22	5.46	6.18	June	4.88	5.11	5.42	6.28	June	----	----	----	----
July	5.32	4.72	4.96	5.25	6.01	5.41	5.23	----	July	----	4.99	5.26	5.98	July	4.72	4.92	5.23	6.04	July	----	----	----	----
Aug.	5.05	4.49	4.72	5.00	5.66	5.10	4.98	----	Aug.	----	4.75	5.01	5.55	Aug.	4.49	4.68	4.98	5.77	Aug.	----	----	----	----
Sept.	5.05	4.53	4.72	5.01	5.66	5.10	5.00	----	Sept.	----	4.74	5.01	5.53	Sept.	4.53	4.70	5.00	5.78	Sept.	----	----	----	----
Oct.	5.15	4.68	4.83	5.09	5.72	5.20	5.08	----	Oct.	----	4.89	5.10	5.62	Oct.	4.68	4.77	5.07	5.81	Oct.	----	----	----	----
Nov.	5.37	4.87	5.07	5.33	5.92	5.45	5.29	----	Nov.	----	5.12	5.37	5.85	Nov.	4.87	5.02	5.29	5.99	Nov.	----	----	----	----
Dec.	5.55	5.02	5.26	5.52	6.10	5.64	5.46	----	Dec.	----	5.32	5.56	6.04	Dec.	5.02	5.19	5.47	6.15	Dec.	----	----	----	----
2011																							
Jan.	5.56	5.04	5.26	5.53	6.09	5.64	5.46	----	Jan.	----	5.29	5.57	6.06	Jan.	5.04	5.22	5.48	6.11	Jan.	----	----	----	----
Feb.	5.66	5.22	5.37	5.64	6.15	5.73	5.58	----	Feb.	----	5.42	5.68	6.10	Feb.	5.22	5.31	5.59	6.19	Feb.	----	----	----	----
Mar.	5.55	5.13	5.28	5.52	6.03	5.62	5.48	----	Mar.	----	5.33	5.56	5.97	Mar.	5.13	5.22	5.48	6.09	Mar.	----	----	----	----
Apr.	5.56	5.16	5.29	5.52	6.02	5.62	5.49	----	Apr.	----	5.32	5.55	5.98	Apr.	5.16	5.25	5.48	6.06	Apr.	----	----	----	----
May	5.33	4.96	5.06	5.29	5.78	5.38	5.27	----	May	----	5.08	5.32	5.74	May	4.96	5.04	5.26	5.81	May	----	----	----	----
June	5.30	4.99	5.04	5.26	5.75	5.33	5.27	----	June	----	5.04	5.26	5.67	June	4.99	5.02	5.25	5.82	June	----	----	----	----
July	5.30	4.93	5.03	5.26	5.76	5.34	5.25	----	July	----	5.05	5.27	5.70	July	4.93	4.99	5.25	5.81	July	----	----	----	----
Aug.	4.79	4.37	4.47	4.74	5.36	4.78	4.79	----	Aug.	----	4.44	4.69	5.22	Aug.	4.37	4.50	4.79	5.49	Aug.	----	----	----	----
Sept.	4.60	4.09	4.23	4.54	5.27	4.61	4.58	----	Sept.	----	4.24	4.48	5.11	Sept.	4.09	4.21	4.59	5.42	Sept.	----	----	----	----
Oct.	4.60	3.98	4.16	4.54	5.37	4.66	4.54	----	Oct.	----	4.21	4.52	5.24	Oct.	3.98	4.11	4.56	5.50	Oct.	----	----	----	----
Nov.	4.39	3.87	3.97	4.34	5.14	4.37	4.41	----	Nov.	----	3.92	4.25	4.93	Nov.	3.87	4.01	4.43	5.34	Nov.	----	----	----	----
Dec.	4.47	3.93	4.03	4.40	5.25	4.47	4.47	----	Dec.	----	4.00	4.33	5.07	Dec.	3.93	4.06	4.46	5.43	Dec.	----	----	----	----
2012																							
Jan.	4.45	3.85	4.01	4.39	5.23	4.48	4.41	----	Jan.	----	4.03	4.34	5.06	Jan.	3.85	3.98	4.43	5.39	Jan.	----	----	----	----
Feb.	4.42	3.85	3.99	4.39	5.14	4.47	4.37	----	Feb.	----	4.02	4.36	5.02	Feb.	3.85	3.96	4.41	5.26	Feb.	----	----	----	----
Mar.	4.54	3.99	4.14	4.51	5.23	4.59	4.50	----	Mar.	----	4.16	4.48	5.13	Mar.	3.99	4.12	4.53	5.33	Mar.	----	----	----	----
Apr.	4.49	3.96	4.08	4.44	5.19	4.53	4.44	----	Apr.	----	4.10	4.40	5.11	Apr.	3.96	4.06	4.48	5.27	Apr.	----	----	----	----
May	4.33	3.80	3.91	4.26	5.07	4.36	4.30	----	May	----	3.92	4.20	4.97	May	3.80	3.90	4.32	5.17	May	----	----	----	----
June	4.22	3.64	3.78	4.14	5.02	4.26	4.18	----	June	----	3.79	4.08	4.91	June	3.64	3.77	4.18	5.13	June	----	----	----	----
July	4.03	3.40	3.54	3.93	4.87	4.12	3.93	----	July	----	3.58	3.93	4.85	July	3.40	3.49	3.93	4.89	July	----	----	----	----
Aug.	4.09	3.48	3.61	3.99	4.91	4.18	3.99	----	Aug.	----	3.65	4.00	4.88	Aug.	3.48	3.57	3.98	4.93	Aug.	----	----	----	----
Sept.	4.09	3.49	3.68	4.01	4.84	4.17	4.00	----	Sept.	----	3.69	4.02	4.81	Sept.	3.49	3.66	4.00	4.87	Sept.	----	----	----	----
Oct.	3.97	3.47	3.63	3.90	4.58	4.05	3.89	----	Oct.	----	3.68	3.91	4.54	Oct.	3.47	3.58	3.89	4.62	Oct.	----	----	----	----
Nov.	3.92	3.50	3.57	3.87	4.51	3.95	3.88	----	Nov.	----	3.60	3.84	4.42	Nov.	3.50	3.54	3.89	4.60	Nov.	----	----	----	----
Dec.	4.05	3.65	3.70	3.98	4.63	4.10	3.99	----	Dec.	----	3.75	4.00	4.56	Dec.	3.65	3.65	3.96	4.70	Dec.	----	----	----	----
2013																							
Jan.	4.19	3.80	3.87	4.14	4.73	4.24	4.14	----	Jan.	----	3.90	4.15	4.66	Jan.	3.80	3.84	4.13	4.81	Jan.	----	----	----	----
Feb.	4.27	3.90	3.95	4.19	4.85	4.29	4.25	----	Feb.	----	3.95	4.18	4.74	Feb.	3.90	3.95	4.20	4.95	Feb.	----	----	----	----
Mar.	4.29	3.93	3.97	4.23	4.85	4.29	4.29	----	Mar.	----	3.95	4.20	4.72	Mar.	3.93	3.98	4.25	4.99	Mar.	----	----	----	----
Apr.	4.07	3.73	3.77	4.03	4.59	4.08	4.07	----	Apr.	----	3.74	4.00	4.49	Apr.	3.73	3.79	4.05	4.69	Apr.	----	----	----	----
May	4.23	3.89	3.94	4.19	4.73	4.24	4.22	----	May	----	3.91	4.17	4.65	May	3.89	3.97	4.20	4.80	May	----	----	----	----
June	4.63	4.27	4.32	4.56	5.19	4.63	4.63	----	June	----	4.27	4.53	5.08	June	4.27	4.36	4.58	5.29	June	----	----	----	----
July	4.76	4.34	4.46	4.69	5.32	4.78	4.74	----	July	----	4.44	4.68	5.21	July	4.34	4.47	4.69	5.43	July	----	----	----	----
Aug.	4.88	4.54	4.63	4.78	5.42	4.85	4.92	----	Aug.	----	4.53	4.73	5.28	Aug.	4.54	4.72	4.83	5.57	Aug.	----	----	----	----
Sept.	4.95	4.64	4.69	4.85	5.47	4.90	4.99	----	Sept.	----	4.58	4.80	5.31	Sept.	4.64	4.80	4.90	5.62	Sept.	----	----	----	----
Oct.	4.82	4.53	4.59	4.73	5.31	4.78	4.86	----	Oct.	----	4.48	4.70	5.17	Oct.	4.53	4.69	4.76	5.44	Oct.	----	----	----	----
Nov.	4.91	4.63	4.67	4.82	5.38	4.86	4.95	----	Nov.	----	4.56	4.77	5.24	Nov.	4.63	4.79	4.85	5.52	Nov.	----	----	----	----
Dec.	4.92	4.62	4.68	4.85	5.38	4.89	4.95	----	Dec.	----	4.59	4.81	5.25	Dec.	4.62	4.76	4.89	5.51	Dec.	----	----	----	----
2014																							
Jan.	4.76	4.49	4.53	4.69	5.19	4.72	4.78	----	Jan.	----	4.44	4.63	5.09	Jan.	4.49	4.62	4.74	5.29	Jan.	----	----	----	----
Feb.	4.68	4.45	4.46	4.60	5.10	4.64	4.71	----	Feb.	----	4.38	4.53	5.01	Feb.	4.45	4.54	4.66	5.19	Feb.	----	----	----	----
Mar.	4.65	4.38	4.44	4.56	5.06	4.63	4.65	----	Mar.	----	4.40	4.51	5.00	Mar.	4.38	4.49	4.60	5.13	Mar.	----	----	----	----
Apr.	4.52	4.24	4.33	4.45	4.90	4.52	4.51	----	Apr.	----	4.30	4.41	4.85	Apr.	4.24	4.36	4.48	4.96	Apr.	----	----	----	----
May	4.38	4.16	4.20	4.31	4.76	4.37	4.40	----	May	----	4.16	4.26	4.69	May	4.16	4.24	4.35	4.83	May	----	----	----	----
June	4.44	4.25	4.26	4.35	4.80	4.42	4.45	----	June	----	4.23	4.29	4.73	June	4.25	4.29	4.41	4.86	June	----	----	----	----
July	4.37	4.16	4.20	4.28	4.73	4.35	4.39	----	July	----	4.16	4.23	4.66	July	4.16	4.23	4.34	4.80	July	----	----	----	----
Aug.	4.29	4.08	4.10	4.20	4.69	4.29	4.30	----	Aug.	----	4.07	4.13	4.65	Aug.	4.08	4.13	4.26	4.72	Aug.	----	----	----	----

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Because of the dearth of Aaa rated public utility bond issues, Moody's Aaa public utility bond yield average was discontinued as of December 10, 2001.

Corporate Bond Yield Averages

	AV. CORP.	CORPORATE BY RATINGS				CORPORATE BY GROUPS		
		Aaa	Aa	A	Baa	P.U.	IND.	R.R.
2009								
Feb.	6.64	5.27	6.02	6.47	8.08	6.72	6.56	----
Mar.	6.84	5.50	6.11	6.66	8.42	6.85	6.83	----
Apr.	6.85	5.39	6.17	6.70	8.39	6.90	6.79	----
May	6.79	5.54	6.24	6.67	8.06	6.83	6.75	----
June	6.52	5.61	6.12	6.39	7.50	6.54	6.49	----
July	6.17	5.41	5.71	6.09	7.09	6.15	6.18	----
Aug.	5.83	5.26	5.45	5.78	6.58	5.80	5.86	----
Sept.	5.61	5.13	5.21	5.56	6.31	5.60	5.62	----
Oct.	5.63	5.15	5.24	5.57	6.29	5.64	5.61	----
Nov.	5.68	5.19	5.29	5.64	6.32	5.71	5.64	----
Dec.	5.78	5.26	5.44	5.77	6.37	5.86	5.71	----
2010								
Jan.	5.76	5.26	5.50	5.76	6.25	5.83	5.69	----
Feb.	5.86	5.35	5.62	5.84	6.34	5.94	5.79	----
Mar.	5.81	5.27	5.57	5.80	6.27	5.90	5.71	----
Apr.	5.80	5.29	5.57	5.78	6.25	5.87	5.71	----
May	5.52	4.96	5.25	5.49	6.05	5.59	5.44	----
June	5.52	4.88	5.16	5.44	6.23	5.62	5.42	----
July	5.32	4.72	4.96	5.25	6.01	5.41	5.23	----
Aug.	5.05	4.49	4.72	5.00	5.66	5.10	4.98	----
Sept.	5.05	4.53	4.72	5.01	5.66	5.10	5.00	----
Oct.	5.15	4.68	4.83	5.09	5.72	5.20	5.08	----
Nov.	5.37	4.87	5.07	5.33	5.92	5.45	5.29	----
Dec.	5.55	5.02	5.26	5.52	6.10	5.64	5.46	----
2011								
Jan.	5.56	5.04	5.26	5.53	6.09	5.64	5.46	----
Feb.	5.66	5.22	5.37	5.64	6.15	5.73	5.58	----
Mar.	5.55	5.13	5.28	5.52	6.03	5.62	5.48	----
Apr.	5.56	5.16	5.29	5.52	6.02	5.62	5.49	----
May	5.33	4.96	5.06	5.29	5.78	5.38	5.27	----
June	5.30	4.99	5.04	5.26	5.75	5.33	5.27	----
July	5.30	4.93	5.03	5.26	5.76	5.34	5.25	----
Aug.	4.79	4.37	4.47	4.74	5.36	4.78	4.79	----
Sept.	4.60	4.09	4.23	4.54	5.27	4.61	4.58	----
Oct.	4.60	3.98	4.16	4.54	5.37	4.66	4.54	----
Nov.	4.39	3.87	3.97	4.34	5.14	4.37	4.41	----
Dec.	4.47	3.93	4.03	4.40	5.25	4.47	4.47	----
2012								
Jan.	4.45	3.85	4.01	4.39	5.23	4.48	4.41	----
Feb.	4.42	3.85	3.99	4.39	5.14	4.47	4.37	----
Mar.	4.54	3.99	4.14	4.51	5.23	4.59	4.50	----
Apr.	4.49	3.96	4.08	4.44	5.19	4.53	4.44	----
May	4.33	3.80	3.91	4.26	5.07	4.36	4.30	----
June	4.22	3.64	3.78	4.14	5.02	4.26	4.18	----
July	4.03	3.40	3.54	3.93	4.87	4.12	3.93	----
Aug.	4.09	3.48	3.61	3.99	4.91	4.18	3.99	----
Sept.	4.09	3.49	3.68	4.01	4.84	4.17	4.00	----
Oct.	3.97	3.47	3.63	3.90	4.58	4.05	3.89	----
Nov.	3.92	3.50	3.57	3.87	4.51	3.95	3.88	----
Dec.	4.05	3.65	3.70	3.98	4.63	4.10	3.99	----
2013								
Jan.	4.19	3.80	3.87	4.14	4.73	4.24	4.14	----
Feb.	4.27	3.90	3.95	4.19	4.85	4.29	4.25	----
Mar.	4.29	3.93	3.97	4.23	4.85	4.29	4.29	----
Apr.	4.07	3.73	3.77	4.03	4.59	4.08	4.07	----
May	4.23	3.89	3.94	4.19	4.73	4.24	4.22	----
June	4.63	4.27	4.32	4.56	5.19	4.63	4.63	----
July	4.76	4.34	4.46	4.69	5.32	4.78	4.74	----
Aug.	4.88	4.54	4.63	4.78	5.42	4.85	4.92	----
Sept.	4.95	4.64	4.69	4.85	5.47	4.90	4.99	----
Oct.	4.82	4.53	4.59	4.73	5.31	4.78	4.86	----
Nov.	4.91	4.63	4.67	4.82	5.38	4.86	4.95	----
Dec.	4.92	4.62	4.68	4.85	5.38	4.89	4.95	----
2014								
Jan.	4.76	4.49	4.53	4.69	5.19	4.72	4.78	----
Feb.	4.68	4.45	4.46	4.60	5.10	4.64	4.71	----
Mar.	4.65	4.38	4.44	4.56	5.06	4.63	4.65	----
Apr.	4.52	4.24	4.33	4.45	4.90	4.52	4.51	----
May	4.38	4.16	4.20	4.31	4.76	4.37	4.40	----
June	4.44	4.25	4.26	4.35	4.80	4.42	4.45	----
July	4.37	4.16	4.20	4.28	4.73	4.35	4.39	----
Aug.	4.29	4.08	4.10	4.20	4.69	4.29	4.30	----
Sept.	4.39	4.11	4.19	4.30	4.80	4.40	4.37	----
Oct.	4.22	3.92	3.99	4.13	4.69	4.24	4.20	----
Nov.	4.28	3.92	4.04	4.18	4.79	4.29	4.26	----
Dec.	4.17	3.79	3.89	4.05	4.74	4.18	4.15	----

	PUBLIC UTILITY BONDS			
	Aaa	Aa	A	Baa
2009				
Feb.	----	6.11	6.30	7.74
Mar.	----	6.14	6.42	8.00
Apr.	----	6.20	6.48	8.03
May	----	6.23	6.49	7.76
June	----	6.13	6.20	7.30
July	----	5.63	5.97	6.87
Aug.	----	5.33	5.71	6.36
Sept.	----	5.15	5.53	6.12
Oct.	----	5.23	5.55	6.14
Nov.	----	5.33	5.64	6.18
Dec.	----	5.52	5.79	6.26
2010				
Jan.	----	5.55	5.77	6.16
Feb.	----	5.69	5.87	6.25
Mar.	----	5.64	5.84	6.22
Apr.	----	5.62	5.81	6.19
May	----	5.29	5.50	5.97
June	----	5.22	5.46	6.18
July	----	4.99	5.26	5.98
Aug.	----	4.75	5.01	5.55
Sept.	----	4.74	5.01	5.53
Oct.	----	4.89	5.10	5.62
Nov.	----	5.12	5.37	5.85
Dec.	----	5.32	5.56	6.04
2011				
Jan.	----	5.29	5.57	6.06
Feb.	----	5.42	5.68	6.10
Mar.	----	5.33	5.56	5.97
Apr.	----	5.32	5.55	5.98
May	----	5.08	5.32	5.74
June	----	5.04	5.26	5.67
July	----	5.05	5.27	5.70
Aug.	----	4.44	4.69	5.22
Sept.	----	4.24	4.48	5.11
Oct.	----	4.21	4.52	5.24
Nov.	----	3.92	4.25	4.93
Dec.	----	4.00	4.33	5.07
2012				
Jan.	----	4.03	4.34	5.06
Feb.	----	4.02	4.36	5.02
Mar.	----	4.16	4.48	5.13
Apr.	----	4.10	4.40	5.11
May	----	3.92	4.20	4.97
June	----	3.79	4.08	4.91
July	----	3.58	3.93	4.85
Aug.	----	3.65	4.00	4.88
Sept.	----	3.69	4.02	4.81
Oct.	----	3.68	3.91	4.54
Nov.	----	3.60	3.84	4.42
Dec.	----	3.75	4.00	4.56
2013				
Jan.	----	3.90	4.15	4.66
Feb.	----	3.95	4.18	4.74
Mar.	----	3.95	4.20	4.72
Apr.	----	3.74	4.00	4.49
May	----	3.91	4.17	4.65
June	----	4.27	4.53	5.08
July	----	4.44	4.68	5.21
Aug.	----	4.53	4.73	5.28
Sept.	----	4.58	4.80	5.31
Oct.	----	4.48	4.70	5.17
Nov.	----	4.56	4.77	5.24
Dec.	----	4.59	4.81	5.25
2014				
Jan.	----	4.44	4.63	5.09
Feb.	----	4.38	4.53	5.01
Mar.	----	4.40	4.51	5.00
Apr.	----	4.30	4.41	4.85
May	----	4.16	4.26	4.69
June	----	4.23	4.29	4.73
July	----	4.16	4.23	4.66
Aug.	----	4.07	4.13	4.65
Sept.	----	4.18	4.24	4.79
Oct.	----	3.98	4.06	4.67
Nov.	----	4.03	4.09	4.75
Dec.	----	3.90	3.95	4.70

	INDUSTRIAL BONDS			
	Aaa	Aa	A	Baa
2009				
Feb.	5.27	5.93	6.62	8.42
Mar.	5.50	6.07	6.90	8.84
Apr.	5.39	6.14	6.90	8.74
May	5.54	6.24	6.84	8.36
June	5.61	6.11	6.58	7.69
July	5.41	5.78	6.20	7.30
Aug.	5.26	5.56	5.84	6.79
Sept.	5.13	5.27	5.58	6.50
Oct.	5.15	5.25	5.59	6.44
Nov.	5.19	5.26	5.64	6.46
Dec.	5.26	5.36	5.74	6.47
2010				
Jan.	5.26	5.44	5.73	6.33
Feb.	5.35	5.55	5.80	6.43
Mar.	5.27	5.49	5.75	6.32
Apr.	5.29	5.50	5.74	6.32
May	4.96	5.19	5.47	6.13
June	4.88	5.11	5.42	6.28
July	4.72	4.92	5.23	6.04
Aug.	4.49	4.68	4.98	5.77
Sept.	4.53	4.70	5.00	5.78
Oct.	4.68	4.77	5.07	5.81
Nov.	4.87	5.02	5.29	5.99
Dec.	5.02	5.19	5.47	6.15
2011				
Jan.	5.04	5.22	5.48	6.11
Feb.	5.22	5.31	5.59	6.19
Mar.	5.13	5.22	5.48	6.09
Apr.	5.16	5.25	5.48	6.06
May	4.96	5.04	5.26	5.81
June	4.99	5.02	5.25	5.82
July	4.93	4.99	5.25	5.81
Aug.	4.37	4.50	4.79	5.49
Sept.	4.09	4.21	4.59	5.42
Oct.	3.98	4.11	4.56	5.50
Nov.	3.87	4.01	4.43	5.34
Dec.	3.93	4.06	4.46	5.43
2012				
Jan.	3.85	3.98	4.43	5.39
Feb.	3.85	3.96	4.41	5.26
Mar.	3.99	4.12	4.53	5.33
Apr.	3.96	4.06	4.48	5.27
May	3.80	3.90	4.32	5.17
June	3.64	3.77	4.18	5.13
July	3.40	3.49	3.93	4.89
Aug.	3.48	3.57	3.98	4.93
Sept.	3.49	3.66	4.00	4.87
Oct.	3.47	3.58	3.89	4.62
Nov.	3.50	3.54	3.89	4.60
Dec.	3.65	3.65	3.96	4.70
2013				
Jan.	3.80	3.84	4.13	4.81
Feb.	3.90	3.95	4.20	4.95
Mar.	3.93	3.98	4.25	4.99
Apr.	3.73	3.79	4.05	4.69
May	3.89	3.97	4.20	4.80
June	4.27	4.36	4.58	5.29
July	4.34	4.47	4.69	5.43
Aug.	4.54	4.72	4.83	5.57
Sept.	4.64	4.80	4.90	5.62
Oct.	4.53	4.69	4.76	5.44
Nov.	4.63	4.79	4.85	5.52
Dec.	4.62	4.76	4.89	5.51
2014				
Jan.	4.49	4.62	4.74	5.29
Feb.	4.45	4.54	4.66	5.19
Mar.	4.38	4.49	4.60	5.13
Apr.	4.24	4.36	4.48	4.96
May	4.16	4.24	4.35	4.83
June	4.25	4.29	4.41	4.86
July	4.16	4.23	4.34	4.80
Aug.	4.08	4.13	4.26	4.72
Sept.	4.11	4.19	4.35	4.82
Oct.	3.92	4.00	4.20	4.70
Nov.	3.92	4.04	4.27	4.82
Dec.	3.79	3.89	4.15	4.77

	RAILROAD BONDS			
	Aaa	Aa	A	Baa
2009				
Feb.	----	----	----	----
Mar.	----	----	----	----
Apr.	----	----	----	----
May	----	----	----	----
June	----	----	----	----
July	----	----	----	----
Aug.	----	----	----	----
Sept.	----	----	----	----
Oct.	----	----	----	----
Nov.	----	----	----	----
Dec.	----	----	----	----
2010				
Jan.	----	----	----	----
Feb.	----	----	----	----
Mar.	----	----	----	----
Apr.	----	----	----	----
May	----	----	----	----
June	----	----	----	----
July	----	----	----	----
Aug.	----	----	----	----
Sept.	----	----	----	----
Oct.	----	----	----	----
Nov.	----	----	----	----
Dec.	----	----	----	----
2011				
Jan.	----	----	----	----
Feb.	----	----	----	----
Mar.	----	----	----	----
Apr.	----	----	----	----
May	----	----	----	----
June	----	----	----	----
July	----	----	----	----
Aug.	----	----	----	----
Sept.	----	----	----	----
Oct.	----	----	----	----
Nov.	----	----	----	----
Dec.	----	----	----	----
2012				
Jan.	----	----	----	----
Feb.	----	----	----	----
Mar.	----	----	----	----
Apr.	----	----	----	----
May	----	----	----	----
June	----	----	----	----
July	----	----	----	----
Aug.	----	----	----	----
Sept.	----	----	----	----
Oct.	----	----	----	----
Nov.	----	----	----	----
Dec.	----	----	----	----
2013				
Jan.	----	----	----	----
Feb.	----	----	----	----
Mar.	----	----	----	----
Apr.	----	----	----	----
May	----	----	----	----
June	----	----	----	----
July	----	----	----	----
Aug.	----	----	----	----
Sept.	----	----	----	----
Oct.	----	----	----	----
Nov.	----	----	----	----
Dec.	----	----	----	----
2014				
Jan.	----	----	----	----
Feb.	----	----	----	----
Mar.	----	----	----	----
Apr.	----	----	----	----
May	----	----	----	----
June	----	----	----	----
July	----	----	----	----
Aug.	----	----	----	----
Sept.	----	----	----	----
Oct.	----	----	----	----
Nov.	----	----	----	----
Dec.	----	----	----	----

Notes: Moody's® Long-Term Corporate Bond Yield Averages have been published daily since 1929. They are derived from pricing data on a regularly-replenished population of nearly 75 seasoned corporate bonds in the US market, each with current outstandings over $100 million. The bonds have maturities as close as possible to 30 years; they are dropped from the list if their remaining life falls below 20 years, if their ratings change. Bonds with deep discounts or steep premiums to par are generally excluded. All yields are yield-to-maturity calculated on a semi-annual basis. Each observation is an unweighted average, with Average Corporate Yields representing the unweighted average of the corresponding Average Industrial and Average Public Utility observations. Because of the dearth of **Aaa** -rated railroad term bond issues, Moody's® **Aaa** railroad bond yield average was discontinued as of December 18, 1967. Moody's® **Aaa** public utility average suspended from Jan. 1984 thru Sept. 1984. Oct. 1984 figure for last 14 business days only. The Railroad Bond Averages were discontinued as of July 17, 1989 because of insufficient frequently tradable bonds. The July figures were based on 8 business days.

Because of the dearth of Aaa rated public utility bond issues, Moody's Aaa public utility bond yield average was discontinued as of December 10, 2001.

Corporate Bond Yield Averages

	AV. CORP.	Corporate by Ratings Aaa	Aa	A	Baa	Corporate by Groups P.U.	IND.	R.R.		Public Utility Bonds Aaa	Aa	A	Baa		Industrial Bonds Aaa	Aa	A	Baa		Railroad Bonds Aaa	Aa	A	Baa
2011																							
Jan.	5.56	5.04	5.26	5.53	6.09	5.64	5.46	----	Jan.	----	5.29	5.57	6.06	Jan.	5.04	5.22	5.48	6.11	Jan.	----	----	----	----
Feb.	5.66	5.22	5.37	5.64	6.15	5.73	5.58	----	Feb.	----	5.42	5.68	6.10	Feb.	5.22	5.31	5.59	6.19	Feb.	----	----	----	----
Mar.	5.55	5.13	5.28	5.52	6.03	5.62	5.48	----	Mar.	----	5.33	5.56	5.97	Mar.	5.13	5.22	5.48	6.09	Mar.	----	----	----	----
Apr.	5.56	5.16	5.29	5.52	6.02	5.62	5.49	----	Apr.	----	5.32	5.55	5.98	Apr.	5.16	5.25	5.48	6.06	Apr.	----	----	----	----
May	5.33	4.96	5.06	5.29	5.78	5.38	5.27	----	May	----	5.08	5.32	5.74	May	4.96	5.04	5.26	5.81	May	----	----	----	----
June	5.30	4.99	5.04	5.26	5.75	5.33	5.27	----	June	----	5.04	5.26	5.67	June	4.99	5.02	5.25	5.82	June	----	----	----	----
July	5.30	4.93	5.03	5.26	5.76	5.34	5.25	----	July	----	5.05	5.27	5.70	July	4.93	4.99	5.25	5.81	July	----	----	----	----
Aug.	4.79	4.37	4.47	4.74	5.36	4.78	4.79	----	Aug.	----	4.44	4.69	5.22	Aug.	4.37	4.50	4.79	5.49	Aug.	----	----	----	----
Sept.	4.60	4.09	4.23	4.54	5.27	4.61	4.58	----	Sept.	----	4.24	4.48	5.11	Sept.	4.09	4.21	4.59	5.42	Sept.	----	----	----	----
Oct.	4.60	3.98	4.16	4.54	5.37	4.66	4.54	----	Oct.	----	4.21	4.52	5.24	Oct.	3.98	4.11	4.56	5.50	Oct.	----	----	----	----
Nov.	4.39	3.87	3.97	4.34	5.14	4.37	4.41	----	Nov.	----	3.92	4.25	4.93	Nov.	3.87	4.01	4.43	5.34	Nov.	----	----	----	----
Dec.	4.47	3.93	4.03	4.40	5.25	4.47	4.47	----	Dec.	----	4.00	4.33	5.07	Dec.	3.93	4.06	4.46	5.43	Dec.	----	----	----	----
2012																							
Jan.	4.45	3.85	4.01	4.39	5.23	4.48	4.41	----	Jan.	----	4.03	4.34	5.06	Jan.	3.85	3.98	4.43	5.39	Jan.	----	----	----	----
Feb.	4.42	3.85	3.99	4.39	5.14	4.47	4.37	----	Feb.	----	4.02	4.36	5.02	Feb.	3.85	3.96	4.41	5.26	Feb.	----	----	----	----
Mar.	4.54	3.99	4.14	4.51	5.23	4.59	4.50	----	Mar.	----	4.16	4.48	5.13	Mar.	3.99	4.12	4.53	5.33	Mar.	----	----	----	----
Apr.	4.49	3.96	4.08	4.44	5.19	4.53	4.44	----	Apr.	----	4.10	4.40	5.11	Apr.	3.96	4.06	4.48	5.27	Apr.	----	----	----	----
May	4.33	3.80	3.91	4.26	5.07	4.36	4.30	----	May	----	3.92	4.20	4.97	May	3.80	3.90	4.32	5.17	May	----	----	----	----
June	4.22	3.64	3.78	4.14	5.02	4.26	4.18	----	June	----	3.79	4.08	4.91	June	3.64	3.77	4.18	5.13	June	----	----	----	----
July	4.03	3.40	3.54	3.93	4.87	4.12	3.93	----	July	----	3.58	3.93	4.85	July	3.40	3.49	3.93	4.89	July	----	----	----	----
Aug.	4.09	3.48	3.61	3.99	4.91	4.18	3.99	----	Aug.	----	3.65	4.00	4.88	Aug.	3.48	3.57	3.98	4.93	Aug.	----	----	----	----
Sept.	4.09	3.49	3.68	4.01	4.84	4.17	4.00	----	Sept.	----	3.69	4.02	4.81	Sept.	3.49	3.66	4.00	4.87	Sept.	----	----	----	----
Oct.	3.97	3.47	3.63	3.90	4.58	4.05	3.89	----	Oct.	----	3.68	3.91	4.54	Oct.	3.47	3.58	3.89	4.62	Oct.	----	----	----	----
Nov.	3.92	3.50	3.57	3.87	4.51	3.95	3.88	----	Nov.	----	3.60	3.84	4.42	Nov.	3.50	3.54	3.89	4.60	Nov.	----	----	----	----
Dec.	4.05	3.65	3.70	3.98	4.63	4.10	3.99	----	Dec.	----	3.75	4.00	4.56	Dec.	3.65	3.65	3.96	4.70	Dec.	----	----	----	----
2013																							
Jan.	4.19	3.80	3.87	4.14	4.73	4.24	4.14	----	Jan.	----	3.90	4.15	4.66	Jan.	3.80	3.84	4.13	4.81	Jan.	----	----	----	----
Feb.	4.27	3.90	3.95	4.19	4.85	4.29	4.25	----	Feb.	----	3.95	4.18	4.74	Feb.	3.90	3.95	4.20	4.95	Feb.	----	----	----	----
Mar.	4.29	3.93	3.97	4.23	4.85	4.29	4.29	----	Mar.	----	3.95	4.20	4.72	Mar.	3.93	3.98	4.25	4.99	Mar.	----	----	----	----
Apr.	4.07	3.73	3.77	4.03	4.59	4.08	4.07	----	Apr.	----	3.74	4.00	4.49	Apr.	3.73	3.79	4.05	4.69	Apr.	----	----	----	----
May	4.23	3.89	3.94	4.19	4.73	4.24	4.22	----	May	----	3.91	4.17	4.65	May	3.89	3.97	4.20	4.80	May	----	----	----	----
June	4.63	4.27	4.32	4.56	5.19	4.63	4.63	----	June	----	4.27	4.53	5.08	June	4.27	4.36	4.58	5.29	June	----	----	----	----
July	4.76	4.34	4.46	4.69	5.32	4.78	4.74	----	July	----	4.44	4.68	5.21	July	4.34	4.47	4.69	5.43	July	----	----	----	----
Aug.	4.88	4.54	4.63	4.78	5.42	4.85	4.92	----	Aug.	----	4.53	4.73	5.28	Aug.	4.54	4.72	4.83	5.57	Aug.	----	----	----	----
Sept.	4.95	4.64	4.69	4.85	5.47	4.90	4.99	----	Sept.	----	4.58	4.80	5.31	Sept.	4.64	4.80	4.90	5.62	Sept.	----	----	----	----
Oct.	4.82	4.53	4.59	4.73	5.31	4.78	4.86	----	Oct.	----	4.48	4.70	5.17	Oct.	4.53	4.69	4.76	5.44	Oct.	----	----	----	----
Nov.	4.91	4.63	4.67	4.82	5.38	4.86	4.95	----	Nov.	----	4.56	4.77	5.24	Nov.	4.63	4.79	4.85	5.52	Nov.	----	----	----	----
Dec.	4.92	4.62	4.68	4.85	5.38	4.89	4.95	----	Dec.	----	4.59	4.81	5.25	Dec.	4.62	4.76	4.89	5.51	Dec.	----	----	----	----
2014																							
Jan.	4.76	4.49	4.53	4.69	5.19	4.72	4.78	----	Jan.	----	4.44	4.63	5.09	Jan.	4.49	4.62	4.74	5.29	Jan.	----	----	----	----
Feb.	4.68	4.45	4.46	4.60	5.10	4.64	4.71	----	Feb.	----	4.38	4.53	5.01	Feb.	4.45	4.54	4.66	5.19	Feb.	----	----	----	----
Mar.	4.65	4.38	4.44	4.56	5.06	4.63	4.65	----	Mar.	----	4.40	4.51	5.00	Mar.	4.38	4.49	4.60	5.13	Mar.	----	----	----	----
Apr.	4.52	4.24	4.33	4.45	4.90	4.52	4.51	----	Apr.	----	4.30	4.41	4.85	Apr.	4.24	4.36	4.48	4.96	Apr.	----	----	----	----
May	4.38	4.16	4.20	4.31	4.76	4.37	4.40	----	May	----	4.16	4.26	4.69	May	4.16	4.24	4.35	4.83	May	----	----	----	----
June	4.44	4.25	4.26	4.35	4.80	4.42	4.45	----	June	----	4.23	4.29	4.73	June	4.25	4.29	4.41	4.86	June	----	----	----	----
July	4.37	4.16	4.20	4.28	4.73	4.35	4.39	----	July	----	4.16	4.23	4.66	July	4.16	4.23	4.34	4.80	July	----	----	----	----
Aug.	4.29	4.08	4.10	4.20	4.69	4.29	4.30	----	Aug.	----	4.07	4.13	4.65	Aug.	4.08	4.13	4.26	4.72	Aug.	----	----	----	----
Sept.	4.39	4.11	4.19	4.30	4.80	4.40	4.37	----	Sept.	----	4.18	4.24	4.79	Sept.	4.11	4.19	4.35	4.82	Sept.	----	----	----	----
Oct.	4.22	3.92	3.99	4.13	4.69	4.24	4.20	----	Oct.	----	3.98	4.06	4.67	Oct.	3.92	4.00	4.20	4.70	Oct.	----	----	----	----
Nov.	4.28	3.92	4.04	4.18	4.79	4.29	4.26	----	Nov.	----	4.03	4.09	4.75	Nov.	3.92	4.04	4.27	4.82	Nov.	----	----	----	----
Dec.	4.17	3.79	3.89	4.05	4.74	4.18	4.15	----	Dec.	----	3.90	3.95	4.70	Dec.	3.79	3.89	4.15	4.77					
2015																							
Jan.	3.84	3.46	3.54	3.70	4.45	3.83	3.84	----	Jan.	----	3.52	3.58	4.39	Jan.	3.46	3.55	3.82	4.51	Jan.	----	----	----	----
Feb.	3.93	3.61	3.64	3.81	4.51	3.91	3.94	----	Feb.	----	3.62	3.67	4.44	Feb.	3.61	3.65	3.94	4.57	Feb.	----	----	----	----
Mar.	3.98	3.64	3.70	3.85	4.54	3.97	3.97	----	Mar.	----	3.67	3.74	4.51	Mar.	3.64	3.72	3.96	4.56	Mar.	----	----	----	----
Apr.	3.93	3.52	3.64	3.82	4.48	3.96	3.88	----	Apr.	----	3.63	3.75	4.51	Apr.	3.52	3.65	3.89	4.45	Apr.	----	----	----	----
May	4.35	3.98	4.07	4.24	4.89	4.38	4.31	----	May	----	4.05	4.17	4.91	May	3.98	4.09	4.30	4.86	May	----	----	----	----
June	4.56	4.19	4.27	4.45	5.13	4.60	4.52	----	June	----	4.29	4.39	5.13	June	4.19	4.25	4.51	5.12	June	----	----	----	----
July	4.57	4.15	4.25	4.44	5.20	4.63	4.51	----	July	----	4.27	4.40	5.22	July	4.15	4.22	4.49	5.18	July	----	----	----	----
Aug.	4.48	4.04	4.13	4.32	5.19	4.54	4.42	----	Aug.	----	4.13	4.25	5.23	Aug.	4.04	4.11	4.39	5.15	Aug.	----	----	----	----
Sept.	4.59	4.07	4.21	4.43	5.34	4.68	4.49	----	Sept.	----	4.25	4.39	5.42	Sept.	4.07	4.16	4.46	5.25	Sept.	----	----	----	----
Oct.	4.52	3.95	4.11	4.33	5.34	4.63	4.40	----	Oct.	----	4.13	4.29	5.47	Oct.	3.95	4.08	4.37	5.21	Oct.	----	----	----	----
Nov.	4.62	4.06	4.21	4.43	5.46	4.73	4.51	----	Nov.	----	4.22	4.40	5.57	Nov.	4.06	4.20	4.45	5.34	Nov.	----	----	----	----
Dec.	4.58	3.97	4.16	4.38	5.46	4.69	4.47	----	Dec.	----	4.16	4.35	5.55	Dec.	3.97	4.16	4.40	5.36	Dec.	----	----	----	----
2016																							
Jan.	4.56	4.00	4.12	4.35	5.45	4.62	4.50	----	Jan.	----	4.09	4.27	5.49	Jan.	4.00	4.16	4.42	5.40	Jan.	----	----	----	----
Feb.	4.44	3.96	3.98	4.22	5.34	4.44	4.43	----	Feb.	----	3.94	4.11	5.28	Feb.	3.96	4.02	4.33	5.39	Feb.	----	----	----	----
Mar.	4.33	3.82	3.91	4.16	5.13	4.40	4.25	----	Mar.	----	3.93	4.16	5.12	Mar.	3.82	3.89	4.16	5.14	Mar.	----	----	----	----
Apr.	4.09	3.62	3.71	3.98	4.79	4.16	4.01	----	Apr.	----	3.74	4.00	4.75	Apr.	3.62	3.67	3.95	4.82	Apr.	----	----	----	----
May	4.04	3.65	3.70	3.94	4.68	4.06	4.02	----	May	----	3.65	3.93	4.60	May	3.65	3.73	3.95	4.75	May	----	----	----	----
June	3.91	3.50	3.60	3.80	4.53	3.93	3.88	----	June	----	3.56	3.78	4.47	June	3.50	3.63	3.82	4.58	June	----	----	----	----
July	3.67	3.28	3.39	3.58	4.22	3.70	3.64	----	July	----	3.36	3.57	4.16	July	3.28	3.42	3.58	4.27	July	----	----	----	----
Aug.	3.70	3.32	3.42	3.60	4.24	3.73	3.66	----	Aug.	----	3.39	3.59	4.20	Aug.	3.32	3.45	3.61	4.27	Aug.	----	----	----	----
Sept.	3.78	3.41	3.50	3.68	4.31	3.80	3.75	----	Sept.	----	3.47	3.66	4.27	Sept.	3.41	3.53	3.69	4.35	Sept.	----	----	----	----
Oct.	3.87	3.51	3.61	3.78	4.38	3.90	3.84	----	Oct.	----	3.59	3.77	4.34	Oct.	3.51	3.63	3.79	4.40	Oct.	----	----	----	----
Nov.	4.20	3.86	3.94	4.11	4.71	4.21	4.19	----	Nov.	----	3.91	4.08	4.64	Nov.	3.86	3.97	4.14	4.77	Nov.	----	----	----	----
Dec.	4.36	4.06	4.12	4.28	4.83	4.39	4.33	----	Dec.	----	4.11	4.27	4.79	Dec.	4.06	4.13	4.29	4.85	Dec.	----	----	----	----
2017																							
Jan.	4.22	3.92	3.98	4.16	4.66	4.24	4.20	----	Jan.	----	3.96	4.14	4.62	Jan.	3.92	4.00	4.17	4.70	Jan.	----	----	----	----
Feb.	4.23	3.95	4.01	4.18	4.64	4.25	4.21	----	Feb.	----	3.99	4.18	4.58	Feb.	3.95	4.02	4.19	4.70	Feb.	----	----	----	----
Mar.	4.28	4.01	4.06	4.23	4.68	4.30	4.27	----	Mar.	----	4.04	4.23	4.62	Mar.	4.01	4.07	4.23	4.74	Mar.	----	----	----	----
Apr.	4.16	3.87	3.93	4.12	4.57	4.19	4.13	----	Apr.	----	3.93	4.12	4.51	Apr.	3.87	3.92	4.11	4.62	Apr.	----	----	----	----
May	4.15	3.85	3.93	4.11	4.55	4.19	4.12	----	May	----	3.94	4.12	4.50	May	3.85	3.92	4.09	4.60	May	----	----	----	----
June	3.98	3.68	3.78	3.93	4.37	4.01	3.95	----	June	----	3.77	3.94	4.32	June	3.68	3.78	3.92	4.41	June	----	----	----	----

Notes: Moody's® Long-Term Corporate Bond Yield Averages have been published daily since 1929. They are derived from pricing data on a regularly-replenished population of over 100 seasoned corporate bonds in the US market, each with current outstandings over $100 million. The bonds have maturities as close as possible to 30 years, with an average maturity of 28 years. They are dropped from the list if their remaining life falls below 20 years or if their ratings change. Bonds with deep discounts or steep premiums to par are generally excluded. All yields are yield-to-maturity calculated on a semi-annual compounding basis. Each observation is an unweighted average, with Average Corporate Yields representing the unweighted average of the corresponding Average Industrial and Average Public Utility observations. Because of the dearth of **Aaa** -rated railroad term bond issues, Moody's® **Aaa** railroad bond yield average was discontinued as of December 18, 1967. Moody's® **Aaa** public utility average was suspended from Jan. 1984 thru Sept. 1984. Oct. 1984 figure for last 14 business days only. The Railroad Bond Averages were discontinued as of July 17, 1989 because of insufficient frequently tradable bonds. The July figures were based on 8 business days.
Because of the dearth of Aaa rated public utility bond issues, Moody's® Aaa public utility bond yield average was discontinued as of December 10, 2001.

Corporate Bond Yield Averages

	AV. CORP.	CORPORATE BY RATINGS Aaa	Aa	A	Baa	CORPORATE BY GROUPS P.U.	IND.	R.R.		PUBLIC UTILITY BONDS Aaa	Aa	A	Baa		INDUSTRIAL BONDS Aaa	Aa	A	Baa		RAILROAD BONDS Aaa	Aa	A	Baa
2013																							
Jan.	4.19	3.80	3.87	4.14	4.73	4.24	4.14	----	Jan.	----	3.90	4.15	4.66	Jan.	3.80	3.84	4.13	4.81	Jan.	----	----	----	----
Feb.	4.27	3.90	3.95	4.19	4.85	4.29	4.25	----	Feb.	----	3.95	4.18	4.74	Feb.	3.90	3.95	4.20	4.95	Feb.	----	----	----	----
Mar.	4.29	3.93	3.97	4.23	4.85	4.29	4.29	----	Mar.	----	3.95	4.20	4.72	Mar.	3.93	3.98	4.25	4.99	Mar.	----	----	----	----
Apr.	4.07	3.73	3.77	4.03	4.59	4.08	4.07	----	Apr.	----	3.74	4.00	4.49	Apr.	3.73	3.79	4.05	4.69	Apr.	----	----	----	----
May	4.23	3.89	3.94	4.19	4.73	4.24	4.22	----	May	----	3.91	4.17	4.65	May	3.89	3.97	4.20	4.80	May	----	----	----	----
June	4.63	4.27	4.32	4.56	5.19	4.63	4.63	----	June	----	4.27	4.53	5.08	June	4.27	4.36	4.58	5.29	June	----	----	----	----
July	4.76	4.34	4.46	4.69	5.32	4.78	4.74	----	July	----	4.44	4.68	5.21	July	4.34	4.47	4.69	5.43	July	----	----	----	----
Aug.	4.88	4.54	4.63	4.78	5.42	4.85	4.92	----	Aug.	----	4.53	4.73	5.28	Aug.	4.54	4.72	4.83	5.57	Aug.	----	----	----	----
Sept.	4.95	4.64	4.69	4.85	5.47	4.90	4.99	----	Sept.	----	4.58	4.80	5.31	Sept.	4.64	4.80	4.90	5.62	Sept.	----	----	----	----
Oct.	4.82	4.53	4.59	4.73	5.31	4.78	4.86	----	Oct.	----	4.48	4.70	5.17	Oct.	4.53	4.69	4.76	5.44	Oct.	----	----	----	----
Nov.	4.91	4.63	4.67	4.82	5.38	4.86	4.95	----	Nov.	----	4.56	4.77	5.24	Nov.	4.63	4.79	4.85	5.52	Nov.	----	----	----	----
Dec.	4.92	4.62	4.68	4.85	5.38	4.89	4.95	----	Dec.	----	4.59	4.81	5.25	Dec.	4.62	4.76	4.89	5.51	Dec.	----	----	----	----
2014																							
Jan.	4.76	4.49	4.53	4.69	5.19	4.72	4.78	----	Jan.	----	4.44	4.63	5.09	Jan.	4.49	4.62	4.74	5.29	Jan.	----	----	----	----
Feb.	4.68	4.45	4.46	4.60	5.10	4.64	4.71	----	Feb.	----	4.38	4.53	5.01	Feb.	4.45	4.54	4.66	5.19	Feb.	----	----	----	----
Mar.	4.65	4.38	4.44	4.56	5.06	4.63	4.65	----	Mar.	----	4.40	4.51	5.00	Mar.	4.38	4.49	4.60	5.13	Mar.	----	----	----	----
Apr.	4.52	4.24	4.33	4.45	4.90	4.52	4.51	----	Apr.	----	4.30	4.41	4.85	Apr.	4.24	4.36	4.48	4.96	Apr.	----	----	----	----
May	4.38	4.16	4.20	4.31	4.76	4.37	4.40	----	May	----	4.16	4.26	4.69	May	4.16	4.24	4.35	4.83	May	----	----	----	----
June	4.44	4.25	4.26	4.35	4.80	4.42	4.45	----	June	----	4.23	4.29	4.73	June	4.25	4.29	4.41	4.86	June	----	----	----	----
July	4.37	4.16	4.20	4.28	4.73	4.35	4.39	----	July	----	4.16	4.23	4.66	July	4.16	4.23	4.34	4.80	July	----	----	----	----
Aug.	4.29	4.08	4.10	4.20	4.69	4.29	4.30	----	Aug.	----	4.07	4.13	4.65	Aug.	4.08	4.13	4.26	4.72	Aug.	----	----	----	----
Sept.	4.39	4.11	4.19	4.30	4.80	4.40	4.37	----	Sept.	----	4.18	4.24	4.79	Sept.	4.11	4.19	4.35	4.82	Sept.	----	----	----	----
Oct.	4.22	3.92	3.99	4.13	4.69	4.24	4.20	----	Oct.	----	3.98	4.06	4.67	Oct.	3.92	4.00	4.20	4.70	Oct.	----	----	----	----
Nov.	4.28	3.92	4.04	4.18	4.79	4.29	4.26	----	Nov.	----	4.03	4.09	4.75	Nov.	3.92	4.04	4.27	4.82	Nov.	----	----	----	----
Dec.	4.17	3.79	3.89	4.05	4.74	4.18	4.15	----	Dec.	----	3.90	3.95	4.70	Dec.	3.79	3.89	4.15	4.77					
2015																							
Jan.	3.84	3.46	3.54	3.70	4.45	3.83	3.84	----	Jan.	----	3.52	3.58	4.39	Jan.	3.46	3.55	3.82	4.51	Jan.	----	----	----	----
Feb.	3.93	3.61	3.64	3.81	4.51	3.91	3.94	----	Feb.	----	3.62	3.67	4.44	Feb.	3.61	3.65	3.94	4.57	Feb.	----	----	----	----
Mar.	3.98	3.64	3.70	3.85	4.54	3.97	3.97	----	Mar.	----	3.67	3.74	4.51	Mar.	3.64	3.72	3.96	4.56	Mar.	----	----	----	----
Apr.	3.93	3.52	3.64	3.82	4.48	3.96	3.88	----	Apr.	----	3.63	3.75	4.51	Apr.	3.52	3.65	3.89	4.45	Apr.	----	----	----	----
May	4.35	3.98	4.07	4.24	4.89	4.38	4.31	----	May	----	4.05	4.17	4.91	May	3.98	4.09	4.30	4.86	May	----	----	----	----
June	4.56	4.19	4.27	4.45	5.13	4.60	4.52	----	June	----	4.29	4.39	5.13	June	4.19	4.25	4.51	5.12	June	----	----	----	----
July	4.57	4.15	4.25	4.44	5.20	4.63	4.51	----	July	----	4.27	4.40	5.22	July	4.15	4.22	4.49	5.18	July	----	----	----	----
Aug.	4.48	4.04	4.13	4.32	5.19	4.54	4.42	----	Aug.	----	4.13	4.25	5.23	Aug.	4.04	4.11	4.39	5.15	Aug.	----	----	----	----
Sept.	4.59	4.07	4.21	4.43	5.34	4.68	4.49	----	Sept.	----	4.25	4.39	5.42	Sept.	4.07	4.16	4.46	5.25	Sept.	----	----	----	----
Oct.	4.52	3.95	4.11	4.33	5.34	4.63	4.40	----	Oct.	----	4.13	4.29	5.47	Oct.	3.95	4.08	4.37	5.21	Oct.	----	----	----	----
Nov.	4.62	4.06	4.21	4.43	5.46	4.73	4.51	----	Nov.	----	4.22	4.40	5.57	Nov.	4.06	4.20	4.45	5.34	Nov.	----	----	----	----
Dec.	4.58	3.97	4.16	4.38	5.46	4.69	4.47	----	Dec.	----	4.16	4.35	5.55	Dec.	3.97	4.16	4.40	5.36	Dec.	----	----	----	----
2016																							
Jan.	4.56	4.00	4.12	4.35	5.45	4.62	4.50	----	Jan.	----	4.09	4.27	5.49	Jan.	4.00	4.16	4.42	5.40	Jan.	----	----	----	----
Feb.	4.44	3.96	3.98	4.22	5.34	4.44	4.43	----	Feb.	----	3.94	4.11	5.28	Feb.	3.96	4.02	4.33	5.39	Feb.	----	----	----	----
Mar.	4.33	3.82	3.91	4.16	5.13	4.40	4.25	----	Mar.	----	3.93	4.16	5.12	Mar.	3.82	3.89	4.16	5.14	Mar.	----	----	----	----
Apr.	4.09	3.62	3.71	3.98	4.79	4.16	4.01	----	Apr.	----	3.74	4.00	4.75	Apr.	3.62	3.67	3.95	4.82	Apr.	----	----	----	----
May	4.04	3.65	3.70	3.94	4.68	4.06	4.02	----	May	----	3.65	3.93	4.60	May	3.65	3.73	3.95	4.75	May	----	----	----	----
June	3.91	3.50	3.60	3.80	4.53	3.93	3.88	----	June	----	3.56	3.78	4.47	June	3.50	3.63	3.82	4.58	June	----	----	----	----
July	3.67	3.28	3.39	3.58	4.22	3.70	3.64	----	July	----	3.36	3.57	4.16	July	3.28	3.42	3.58	4.27	July	----	----	----	----
Aug.	3.70	3.32	3.42	3.60	4.24	3.73	3.66	----	Aug.	----	3.39	3.59	4.20	Aug.	3.32	3.45	3.61	4.27	Aug.	----	----	----	----
Sept.	3.78	3.41	3.50	3.68	4.31	3.80	3.75	----	Sept.	----	3.47	3.66	4.27	Sept.	3.41	3.53	3.69	4.35	Sept.	----	----	----	----
Oct.	3.87	3.51	3.61	3.78	4.38	3.90	3.84	----	Oct.	----	3.59	3.77	4.34	Oct.	3.51	3.63	3.79	4.40	Oct.	----	----	----	----
Nov.	4.20	3.86	3.94	4.11	4.71	4.21	4.19	----	Nov.	----	3.91	4.08	4.64	Nov.	3.86	3.97	4.14	4.77	Nov.	----	----	----	----
Dec.	4.36	4.06	4.12	4.28	4.83	4.39	4.33	----	Dec.	----	4.11	4.27	4.79	Dec.	4.06	4.13	4.29	4.85	Dec.	----	----	----	----
2017																							
Jan.	4.22	3.92	3.98	4.16	4.66	4.24	4.20	----	Jan.	----	3.96	4.14	4.62	Jan.	3.92	4.00	4.17	4.70	Jan.	----	----	----	----
Feb.	4.23	3.95	4.01	4.18	4.64	4.25	4.21	----	Feb.	----	3.99	4.18	4.58	Feb.	3.95	4.02	4.19	4.70	Feb.	----	----	----	----
Mar.	4.28	4.01	4.06	4.23	4.68	4.30	4.27	----	Mar.	----	4.04	4.23	4.62	Mar.	4.01	4.07	4.23	4.74	Mar.	----	----	----	----
Apr.	4.16	3.87	3.93	4.12	4.57	4.19	4.13	----	Apr.	----	3.93	4.12	4.51	Apr.	3.87	3.92	4.11	4.62	Apr.	----	----	----	----
May	4.15	3.85	3.93	4.11	4.55	4.19	4.12	----	May	----	3.94	4.12	4.50	May	3.85	3.92	4.09	4.60	May	----	----	----	----
June	3.98	3.68	3.78	3.93	4.37	4.01	3.95	----	June	----	3.77	3.94	4.32	June	3.68	3.78	3.92	4.41	June	----	----	----	----
July	4.01	3.70	3.80	3.98	4.39	4.06	3.96	----	July	----	3.82	3.99	4.36	July	3.70	3.78	3.95	4.41	July	----	----	----	----
Aug.	3.92	3.63	3.72	3.88	4.31	3.92	3.92	----	Aug.	----	3.67	3.86	4.23	Aug.	3.63	3.76	3.90	4.38	Aug.	----	----	----	----
Sept.	3.92	3.63	3.73	3.88	4.30	3.93	3.91	----	Sept.	----	3.70	3.87	4.24	Sept.	3.63	3.75	3.89	4.37	Sept.	----	----	----	----
Oct.	3.94	3.60	3.75	3.91	4.32	3.97	3.90	----	Oct.	----	3.74	3.91	4.26	Oct.	3.60	3.74	3.90	4.37	Oct.	----	----	----	----
Nov.	3.88	3.57	3.67	3.84	4.27	3.88	3.87	----	Nov.	----	3.65	3.83	4.16	Nov.	3.57	3.68	3.85	4.37	Nov.	----	----	----	----
Dec.	3.83	3.51	3.61	3.79	4.22	3.85	3.80	----	Dec.	----	3.62	3.79	4.14	Dec.	3.51	3.60	3.79	4.31	Dec.	----	----	----	----
2018																							
Jan.	3.88	3.55	3.68	3.85	4.26	3.91	3.85	----	Jan.	----	3.69	3.86	4.18	Jan.	3.55	3.66	3.84	4.33	Jan.	----	----	----	----
Feb.	4.13	3.82	3.95	4.09	4.51	4.15	4.12	----	Feb.	----	3.94	4.09	4.42	Feb.	3.82	3.95	4.09	4.60	Feb.	----	----	----	----
Mar.	4.20	3.87	3.99	4.14	4.64	4.21	4.19	----	Mar.	----	3.97	4.13	4.52	Mar.	3.87	4.00	4.14	4.75	Mar.	----	----	----	----
Apr.	4.22	3.85	4.01	4.17	4.67	4.24	4.20	----	Apr.	----	3.99	4.17	4.58	Apr.	3.85	4.03	4.17	4.76	Apr.	----	----	----	----
May	4.36	4.00	4.12	4.30	4.83	4.36	4.34	----	May	----	4.10	4.28	4.71	May	4.00	4.13	4.31	4.94	May	----	----	----	----
June	4.35	3.96	4.11	4.29	4.83	4.37	4.33	----	June	----	4.11	4.27	4.71	June	3.96	4.11	4.29	4.95	June	----	----	----	----
July	4.31	3.87	4.07	4.26	4.79	4.35	4.26	----	July	----	4.10	4.27	4.67	July	3.87	4.03	4.23	4.91	July	----	----	----	----
Aug.	4.29	3.88	4.05	4.23	4.77	4.33	4.25	----	Aug.	----	4.08	4.26	4.64	Aug.	3.88	4.01	4.20	4.89	Aug.	----	----	----	----
Sept.	4.38	3.98	4.14	4.31	4.88	4.41	4.35	----	Sept.	----	4.18	4.32	4.74	Sept.	3.98	4.09	4.30	5.02	Sept.	----	----	----	----
Oct.	4.54	4.14	4.28	4.46	5.07	4.56	4.52	----	Oct.	----	4.31	4.45	4.91	Oct.	4.14	4.24	4.45	5.22	Oct.	----	----	----	----
Nov.	4.64	4.22	4.37	4.53	5.22	4.65	4.62	----	Nov.	----	4.40	4.52	5.03	Nov.	4.22	4.34	4.53	5.42	Nov.	----	----	----	----
Dec.	4.49	4.02	4.20	4.37	5.13	4.51	4.47	----	Dec.	----	4.24	4.37	4.92	Dec.	4.02	4.16	4.36	5.34	Dec.	----	----	----	----
2019																							
Jan.	4.45	3.93	4.13	4.34	5.12	4.48	4.41	----	Jan.	----	4.18	4.35	4.91	Jan.	3.93	4.07	4.32	5.32	Jan.	----	----	----	----
Feb.	4.31	3.79	3.99	4.23	4.95	4.35	4.27	----	Feb.	----	4.05	4.25	4.76	Feb.	3.79	3.93	4.21	5.13	Feb.	----	----	----	----
Mar.	4.24	3.77	3.92	4.17	4.84	4.26	4.21	----	Mar.	----	3.98	4.16	4.65	Mar.	3.77	3.87	4.17	5.02	Mar.	----	----	----	----
Apr.	4.15	3.69	3.85	4.08	4.70	4.18	4.11	----	Apr.	----	3.91	4.08	4.55	Apr.	3.69	3.79	4.08	4.85	Apr.	----	----	----	----
May	4.08	3.67	3.80	4.01	4.63	4.10	4.06	----	May	----	3.84	3.98	4.47	May	3.67	3.76	4.03	4.78	May	----	----	----	----
June	3.89	3.42	3.59	3.83	4.46	3.93	3.85	----	June	----	3.65	3.82	4.31	June	3.42	3.53	3.84	4.60	June	----	----	----	----
July	3.75	3.29	3.46	3.70	4.28	3.79	3.70	----	July	----	3.53	3.69	4.13	July	3.29	3.38	3.70	4.42	July	----	----	----	----
Aug.	3.36	2.98	3.08	3.32	3.87	3.36	3.36	----	Aug.	----	3.17	3.29	3.63	Aug.	2.98	2.99	3.34	4.11	Aug.	----	----	----	----
Sept.	3.42	3.03	3.14	3.37	3.91	3.44	3.38	----	Sept.	----	3.24	3.37	3.71	Sept.	3.03	3.02	3.35	4.11	Sept.	----	----	----	----
Oct.	3.41	3.01	3.13	3.37	3.93	3.45	3.37	----	Oct.	----	3.24	3.39	3.72	Oct.	3.01	3.01	3.35	4.12	Oct.	----	----	----	----
Nov.	3.44	3.06	3.16	3.40	3.94	3.48	3.40	----	Nov.	----	3.25	3.43	3.76	Nov.	3.06	3.06	3.37	4.12	Nov.	----	----	----	----

Notes: Moody's®Long-Term Corporate Bond Yield Averages have been published daily since 1929. They are derived from pricing data on a regularly-replenished population of over 100 seasoned corporate bonds in the US market, each with current outstandings over $100 million. The bonds have maturities as close as possible to 30 years, with an average maturity of 28 years. They are dropped from the list if their remaining life falls below 20 years or if their ratings change. Bonds with deep discounts or steep premiums to par are generally excluded. All yields are yield-to-maturity calculated on a semi-annual compounding basis. Each observation is an unweighted average, with Average Corporate Yields representing the unweighted average of the corresponding Average Industrial and Average Public Utility observations. Because of the dearth of **Aaa** -rated railroad term bond issues, Moody's® **Aaa** railroad bond yield average was discontinued as of December 18, 1967. Moody's® **Aaa** public utility average was suspended from Jan. 1984 thru Sept. 1984. Oct. 1984 figure for last 14 business days only. The Railroad Bond Averages were discontinued as of July 17, 1989 because of insufficient frequently tradable bonds. The July figures were based on 8 business days.
Because of the dearth of Aaa rated public utility bond issues, Moody's® Aaa public utility bond yield average was discontinued as of December 10, 2001.

RESOLUTION

NO. R-19-457

CITY HALL: <u>November 7, 2019</u>

BY: COUNCILMEMBERS MORENO, WILLIAMS, GIARRUSSO, BANKS AND BROSSETT

REVISED APPLICATION OF ENTERGY NEW ORLEANS, LLC FOR A CHANGE IN ELECTRIC AND GAS RATES PURSUANT TO COUNCIL RESOLUTIONS R-15-194 AND R-17-504 AND FOR RELATED RELIEF

RESOLUTION AND ORDER

DOCKET NO. UD-18-07

WHEREAS, pursuant to the Constitution of the State of Louisiana and the Home Rule Charter of the City of New Orleans ("Charter"), the Council of the City of New Orleans ("Council") is the governmental body with the power of supervision, regulation, and control over public utilities providing service within the City of New Orleans; and

WHEREAS, pursuant to its powers of supervision, regulation and control over public utilities, the Council is responsible for fixing and changing rates and charges of public utilities and making all necessary rules and regulations to govern applications for the fixing and changing of rates and charges of public utilities; and

WHEREAS, Entergy New Orleans, LLC ("ENO" or "Company") provides retail electric service and gas within the City of New Orleans; and

WHEREAS, Council Resolution No. R-17-228 directed ENO to exclude certain costs and accounting entries related to its 2017 internal restructuring from its cost of service studies in its 2018 rate case filing (*i.e.,* the "Application"); and

WHEREAS, Council Resolution No. R-17-504 directed ENO to include in its 2018 rate case filing certain information, the provision of which as part of ENO's filing, the Council expects may serve in the interest of economy, efficiency, and a reduction in regulatory costs as it reviews the Application; and

WHEREAS, Council Resolution No. R-18-97 directed ENO to include as part of its 2018 rate case filing (*i.e.,* the Application) a green pricing proposal under which customers may voluntarily choose to have some or all of their electricity supplied by renewable resources; and

WHEREAS, on July 31, 2018, ENO filed its initial *Application of Entergy New Orleans, LLC for a Change in Electric and Gas Rates Pursuant to Council Resolutions R-15-194 and R-17-504 and For Related Relief* ("Initial Rate Filing"); and

INITIAL RATE FILING

WHEREAS, ENO's Initial Rate Filing proposed a change in electric and gas rates and new rate schedules applicable to electric and gas service; and

WHEREAS, ENO's Initial Rate Filing proposed electric rates that would overall decrease its revenues by approximately $20 million per year and proposed gas rates that would overall decrease its revenues by approximately $0.13 million per year; and

WHEREAS, according to the Company, the total net effects of the initially proposed electric rate changes on typical monthly electric bills are summarized in the following table:

Estimated Typical Monthly Electric Bill Summer ($)					
Customer Type	Energy (kWh)	Demand (kW)	Present Rate	Proposed Rate	Difference
Residential – Legacy	1,000		$122.11	$126.57	$4.46
Residential – Algiers	1,000		$104.28	$126.68	$22.40
Small Electric – Legacy	10	1,825	$242.69	$257.62	$14.93
Small Electric – Algiers	10	1,825	$265.13	$260.08	($5.05)
Large Electric – Legacy	250	91,250	$9,552.67	$8,916.46	($638.21)
Large Electric, HLF - Algiers	250	91,250	$8,439.13	$9,081.85	$642.72

and

WHEREAS, with regard to the electric rate increase initially proposed for Algiers residential customers, the Council noted its disappointment and serious concern regarding ENO's estimated bill impact on Algiers residential customers. One of the primary functions of the Council in its utility regulatory capacity is the establishment of just and reasonable rates. The Council's initial reaction is that such a significant estimated increase will result in rate shock that is patently unacceptable and may be found to be unjust and unreasonable as filed without some form of viable mitigation measures. Accordingly, the Council indicated its intent to direct ENO to file a supplement to its Initial Rate Filing with proposed mitigation measures for the substantial Algiers residential rate increase; and

WHEREAS, in a letter dated August 15, 2018, Roderick K. West, Entergy Group President of Utility Operations, explained that ENO had decided to withdraw its Initial Rate Filing, explaining that the decision to withdraw the Initial Rate Filing was in "response to the thoughtful feedback that Entergy New Orleans has received from members of the Council of the City of New Orleans and the Council's legal and technical Advisors, particularly with regard to the need to develop a better path toward a single rate structure for all customers of Entergy New Orleans, both those residing on the East Bank of New Orleans and those residing in Algiers" and noted that ENO would refile the rate case in September; and

ENO'S REVISED RATE APPLICATION

WHEREAS, on September 21, 2018, ENO refiled its rate case, *Revised Application of Entergy New Orleans, LLC for a Change in Electric and Gas Rates Pursuant to Council Resolutions R-15-194 and R-17-504 and For Related Relief* ("Revised Application"); and

WHEREAS, the Revised Application states that ENO's request has three principal components: (1) a new combined electric rate structure, which realigns the revenue requirement associated with non-fuel capacity and long-term service agreements ("LTSA") from certain riders to base revenue and will recover the cost of Advanced Metering Infrastructure ("AMI"); (2) contemporaneous cost recovery riders for investments in energy efficiency/demand response (also referred to as demand-side management or "DSM"), incremental changes in capacity/LTSA costs, grid modernization investments, and for Gas Infrastructure Replacement investments and related costs; and (3) Formula Rate Plans ("FRP"), one for Electric operations which incorporates a proposed decoupling mechanism as required by the Council, and one for Gas operations; and

WHEREAS, ENO's Revised Application in this proceeding is a full base rate case with test years ending December 31, 2017 (Period I) and December 31, 2018 (Period II); and

WHEREAS, the Revised Application includes ENO's request for a change in electric and gas rates and new rate schedules applicable to electric and gas service; and

WHEREAS, ENO's Revised Application proposed electric rates would overall decrease its revenues by approximately $20 million per year and proposed gas rates would overall decrease its revenues by approximately $0.142 million per year; and

WHEREAS, according to the Company, the net effects of these proposed electric rate changes on typical monthly electric bills are summarized in the following table:

Estimated Typical Monthly Electric Bill (Summer) ($)							
Customer Type	**Energy (kWh)**	**Demand (kW)**	**Present Rate**	**Phase I Proposed Rate - August 2019**	**Difference**	**Phase II Proposed Rate - September 2021**	**Difference**
Residential Legacy	1000		$ 122.11	$124.13	$2.02	$124.13	$-0-
Residential Algiers	1000		$ 104.28	$107.93	$3.65	$111.69	$3.76
Small Electric Legacy	1,825	10	$ 242.69	$252.62	$9.93	$252.62	$-0-
Small Electric Algiers	1,825	10	$ 265.13	$247.27	($17.86)	$247.27	$-0-
Large Electric Legacy	91,250	250	$9,552.67	$9,213.95	($338.72)	$9,213.95	$-0-
Lg. Elec. - HLF Algiers	91,250	250	$8,439.13	$9,236.05	$796.92	$9,192.81	($43.24)

and

WHEREAS, according to the Company, the net effects of these proposed gas rate changes on typical monthly gas bills are summarized in the below table:

Estimated Typical Monthly Gas (Winter) ($)				
Customer Type	**Consumption**	**Present Rate**	**Proposed Rate**	**Difference**
Residential	100 ccf	$82.11	$81.24	($0.87)
Commercial	50 mcf	$428.66	$414.00	($14.66)
Industrial	1,000 mcf	$6,944.09	$6,876.56	($67.53)

and

ENO'S REQUEST FOR RELIEF

WHEREAS, ENO requests the following relief in its Revised Application:

1. That the Council issue an order confirming that Entergy New Orleans' filing, including its Revised Application is in substantial compliance with the Minimum/Standard Filing Requirements;

2. That the Council direct that notice of all matters in these proceedings be sent to Gary E. Huntley and Alyssa Maurice-Anderson, as representatives of ENO;
3. That the Council find that the change in electric and gas rates described herein, but more particularly and specifically described in the testimony and exhibits of the witnesses attached hereto and made part hereof, is in the public interest, will result in just and reasonable rates and, subject to the terms and conditions to be established hereby, fully complies with Louisiana law and the ordinances of the Council;
4. That the Council take official action to grant the Company's request for a change in electric and gas rates, and such other specific requests for which the Company seeks approval herein, including but not limited to the following:
    a. approving the Company's proposed depreciation rates so that the return of capital may be synchronized to the service life of the plant used to provide customers electric service;
    b. approving the Company's proposed electric and natural gas formula rate plans;
    c. approving the other new and revised riders proposed by ENO;
    d. approving after receiving the Company's supplemental application, the new customer service and billing offerings proposed by the Company;
    e. approving the withdrawal of certain rate schedules, as well as the new and modified rate schedules;
    f. approving ENO's recovery of costs associated with the five grid modernization projects proposed in the filing for such projects closing to plant after December 31, 2019, and approves the regulatory review process proposed for use with future grid modernization projects;

g. approving the Company's proposed modifications to ENO's Service Regulations Applicable to Electric and Gas Service;

5. That the Council adopt for application in this proceeding its Official Protective Order as set forth in Resolution No. R-07-432, or provide for such other appropriate protection for any confidential information to be produced in this proceeding;
6. That the Council approve the proposed procedural schedule allowing for ENO to provide supplemental information regarding its new offerings;
7. That the Council grant all other Orders and decrees as may be necessary, and for all general and equitable relief that the law and the nature of the case may permit; and

MINIMUM FILING REQUIREMENTS

WHEREAS, pursuant to Chapter 158 of the Code of the City of New Orleans ("City Code"), when a utility files an application to change rates or services, the application must satisfy certain Minimum Filing Requirements ("MFR"), which requirements provide the information necessary to permit a thorough analysis of the utility's application; and

WHEREAS, ENO states that its Revised Application comports with the MFRs and requests an order confirming that ENO's filing, including its Revised Application is in substantial compliance with the MFRs. However, out of abundance of caution, to the extent that the Council determines that ENO's filing does not meet the referenced MFRs, pursuant to Section 158-48, of the City Code, the Company requests waiver of such requirements. Alternatively, ENO requests that a reasonable opportunity to remedy any such deficiencies be granted by the Council; and

WHEREAS, the Council, in Resolution No. R-18-434, stated that it wished for ENO to comply with the MFRs and will provide ENO a reasonable opportunity to remedy any deficiencies thereof. Further, the Council directed the parties to the instant docket to attempt to amicably resolve any disputes as to whether the Revised Application is in compliance with respect to the MFRs; and

PROCEDURAL MATTERS

WHEREAS, Section 158-91 of the City Code establishes that the Council shall have 12 months from its acceptance of the utility's filing within which to review the filing and to render a determination as to the proper rates to be charged by the utility and if the Council has not made this determination by 12 months plus one day after the date of acceptance, the rates as submitted by the utility in the accepted filing shall become effective subject to refund; and

WHEREAS, ENO addressed the Council's concern that had ENO not withdrawn its initial rate filing and the case been determined within applicable time limits under Section 158-91 of the Code of the City of New Orleans, the proposed decrease in ENO's rates would become effective with the first billing cycle of August 2019. In order to ensure that customers receive potentially lower rates at that same time but without compressing the Council's twelve-month review period, ENO commits that rates ultimately approved by the Council in this proceeding will be effective as of the first billing cycle August 2019 even though a Council decision may not be issued by that time. The Council will direct ENO to make such necessary adjustments to customer bills to reflect the appropriate amounts due to reflect the approved rates retroactively to the first billing cycle of August 2019; and

WHEREAS, in Resolution No. R-18-434, the Council established a procedural schedule to allow the parties to this proceeding to rigorously investigate the Revised Application, conduct discovery, file testimony and otherwise establish a record upon which the Council may rely to render a determination as to the proper rates to be charged by ENO; and

WHEREAS, several parties timely intervened in the docket including the Alliance for Affordable Energy ("AAE"), Air Products and Chemicals, Inc. ("Air Products"), Building Science Innovators, LLC ("BSI"), City of New Orleans, Sewerage and Water Board of New Orleans ("SWB"), Crescent City Power Users Group ("CCPUG"), Justice and Beyond, Sierra Club, and 350 New Orleans; and

WHEREAS, numerous parties evaluated various aspects of the case by issuing hundreds of discovery requests, reviewing thousands of pages of responses, and conducting oral depositions of multiple experts; and

WHEREAS, ENO, AAE, Air Products, CCPUG, BSI, and the Council's Advisors actively participated in the docket and a total of thirty-three (33) expert witnesses provided sworn pre-filed testimony in the case in support of their respective positions; and

WHEREAS, a five-day evidentiary hearing was conducted on June 17, 2019 through June 21, 2019, before the Honorable Jeffrey S. Gulin wherein parties were allowed to cross examine other parties' witnesses and introduce additional evidence into the record; and

WHEREAS, several parties filed initial briefs and reply briefs outlining their positions and setting forth their legal arguments for the Council's consideration; and

WHEREAS, the Council has reviewed ENO's Revised Application, the positions of the parties and the evidence presented in the voluminous record certified in this proceeding and resolved the issues presented as follows; and

RETURN ON EQUITY ("ROE")

WHEREAS, in utility ratemaking, the primary objective is to allow the utility company sufficient revenues to meet its operating expenses, provide its shareholders with a reasonable rate of return ("ROR"), and attract new capital;[1] and

WHEREAS, the ratemaking process involves a complicated set of factors under which the regulator approves rate increases or requires rate decreases for each customer class. Retail rates should allow the utility the opportunity to recover prudently incurred operating and maintenance expenses, taxes, and a fair return on investment that is used and useful in providing utility services;[2] and

WHEREAS, the legal standard for determining what is a fair ROR was articulated in two seminal cases: *Federal Power Comm'n v. Hope Natural Gas Co.*[3] and *Bluefield Waterworks & Improvements Co. v. Public Service Commission of W. Virginia.*[4] In *Bluefield,* the Court observed:

> What annual rate will constitute just compensation depends upon many circumstances, and must be determined by the exercise of a fair and enlightened judgment, having regard to **all relevant facts**. 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 and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but **it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.** A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for

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[1] *Gordon v. Council of City of New Orleans*, 9 So. 3d at 73; citing *Cent. Louisiana Elec. Co. v. Louisiana Pub. Serv. Comm'n,* 508 So. 2d 1361, 1364 (La. 1987); *S. Cent. Bell Tel. Co. v. Louisiana Pub. Serv. Comm'n,* 352 So. 2d 964, 967 (La. 1977).

[2] *Id.*

[3] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 64 S. Ct. 281, 88 L. Ed. 333 (1944) ("*Hope*").

[4] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679, 43 S. Ct. 675, 67 L. Ed. 1176 (1923) ("*Bluefield*").

investment, the money market and business conditions generally.[5] (Emphasis added).

In *Hope*, the Court reiterated these principles, stating:

> **Rates which enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed certainly cannot be condemned as invalid,** ....[6] (Emphasis added); and

WHEREAS, as a general proposition, these cases hold that the rate-making process rests on a balancing of interests between the investors and the consumers;[7] and

WHEREAS, the method used to balance the interests of the investors and the consumers is well established. The initial determination that must be made is the utility's future revenue requirement;[8] and

WHEREAS, as a guide to such a determination, data is generally gathered from some 12-month period taken as a "test year."[9] Customarily, the test year selected is the most recent annual period from which actual operating data is available. The data gathered is then used to calculate the following four variables:

1. The amount of *revenues* generated under the present rate structure.
2. The *operating expenses,* including maintenance, depreciation, and taxes, incurred to produce revenues.
3. The *rate base, i.e.*, the value of the property, plant, and equipment, (less accumulated depreciation) and related non-tangible assets, which provide the service, and on which a return should be earned.

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[5] *Id.* at 692-93, 43 S. Ct. at 679.
[6] *Hope*, 320 U.S. at 605, 64 S. Ct. at 289.
[7] *Cent. Louisiana Elec. Co. v. Louisiana Pub. Serv. Comm'n*, 508 So. 2d at 1365.
[8] *Id.*
[9] *Id.* citing *James C. Bonbright, et al., Principles of Public Utility Rates* 150, n.7 (1961).

4. The *rate of return,* a percentage figure which, when applied to the rate base, will generate revenues sufficient to cover costs and give investors a fair return on their investment;[10] and

WHEREAS, ENO's allowed return on investment can be regarded as its Weighted Average Cost of Capital ("WACC"), which is constituted as a weighting of the return on long term debt components and an allowed-ROE, which can be regarded as the WACC component allowing ENO a profit;[11] and

WHEREAS, accepted regulatory principles and the U.S. Supreme Court's *Hope* and *Bluefield* decisions provide that ENO be allowed a return on its investment that:

1. is comparable to that being earned by other companies with comparable risks,
2. is sufficient to assure confidence in its financial soundness, and
3. is adequate to maintain its credit worthiness and enable it to raise necessary capital;[12] and

WHEREAS, the Council is not obligated to employ any specific methodology when setting ENO's rates, however, both ENO in its Revised Application and the Advisors in their direct testimony calculate their respective proposed rates based on allowing the opportunity for recovery of prudently incurred operating costs, plus a fair return on investment to include a reasonable allowed-ROE, which is an accepted methodology;[13] and

WHEREAS, further, for many years, the Council has repeatedly acknowledged these ratemaking principles set forth in *Hope* and *Bluefield* in a variety of rate proceedings;[14] and

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[10] *Cent. Louisiana Elec. Co. v. Louisiana Pub. Serv. Comm'n*, 508 So. 2d at 1365.

[11] Initial Brief of the Advisors to the City Council of New Orleans, at 26, July 26, 2019 ("Advisors' Initial Brief").

[12] *Bluefield*, 262 U.S. at 692; and *Hope*, 320 U.S. 591.

[13] Advisors' Initial Brief at 27.

[14] Resolution Nos. R-03-272, at 11-12 (resolving rate case Docket No. UD-01-04), R-09-136, at 10 (resolving rate case Docket No. UD-08-03), and R-14-278, at 17-18 (resolving rate case Docket No. UD-13-01), all reference and accept these regulatory ratemaking principles regarding the appropriate allowed return on ENO's investments.

WHEREAS, these variables are then used to determine the "return" (*i.e.*, ROE) that is available to be distributed to the utility's investors and the "actual rate of return" presently being earned by the utility.[15] The "return" or earnings is equal to the utility's revenues less its operating expenses, exclusive of interest.[16] The ratio of the utility's return to its rate base is equal to its actual ROR;[17] and

WHEREAS, as part of the Council's ratemaking authority when setting ENO's retail rates in this proceeding, the concept of ROR specifically means an appropriate WACC whose components are long-term debt total cost and ROE;[18] and

WHEREAS, in its Revised Application, ENO asserts that the Company's ROE lies in the range of 10.25% to 11.25%.[19] Within that range, the Company considers 10.75% to be the best estimate of ENO's Cost of Equity and recommends that the Council adopt a 10.75% ROE;[20] and

WHEREAS, ENO contends that Mr. Hevert is the only witness offering an opinion in this proceeding on ENO's estimated ROE that performed a comprehensive analysis that fairly measured ENO's risk;[21] and

WHEREAS, the Company contends that Mr. Hevert's recommendation results from a balanced approach considering the relative strengths and weaknesses of multiple analytical methodologies as well as considerable empirical and qualitative information in analyzing and giving appropriate weight to their results;[22] and

[15] *Bluefield*, 262 U.S. 692 and *Hope*, 320 U.S. 591.
[16] *Id.*
[17] *Id.*
[18] Advisors' Initial Brief at 27.
[19] Post-Hearing Brief of Entergy New Orleans, LLC, at 44, July 26, 2019 ("ENO Initial Brief").
[20] *Id.*
[21] *Id.* at 41.
[22] *Id.*

WHEREAS, Specifically, Mr. Hevert conducted analyses that included the Discounted Cash Flow ("DCF") model, including the Constant Growth and Multi-Stage forms; the Capital Asset Pricing Model ("CAPM"); the Bond Yield Plus Risk Premium approach; and the Expected Earnings model;[23] and

WHEREAS, ENO argues that the opposing witnesses give considerable weight to the DCF method, even though it produces ROE estimates in some cases more than 150 basis points below the returns authorized for other electric utilities;[24] and

WHEREAS, ENO also proposed a Reliability Incentive Mechanism ("RIM") Plan, which would affect the base rates to be set in this proceeding and afterwards through the proposed Electric FRP.[25] Under the RIM Plan, ENO proposed that the earnings component of its electric base rates be correlated to reliability performance through an adjusted ROE formula, included in the FRP that features a Reliability Adjustment.[26] Under the Company's RIM Plan,[27] ENO is requesting that for the purpose of initially setting rates resulting from this proceeding that a ROE of 10.50% be implemented on its electric Cost of Service based on a negative adjustment of 25 basis points applied to the proposed ROE of 10.75% recommended by Company witness Robert B. Hevert.[28] Through the Company's proposed electric FRP as described by Company witness Phillip B. Gillam, ENO seeks an opportunity to achieve enhanced returns commensurate with the 10.75% recommended by Mr. Hevert as ENO realizes increases in electric service reliability.[29] According

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[23] *Id.* at 42.
[24] *Id.*
[25] Ex. No. ENO-55 at 2.
[26] *Id.*
[27] Ex. No. ENO-2 at 23:1-30:5 (HSPM).
[28] Ex. No. ENO-55 at 21.
[29] *Id.* at 21-22.

to ENO, the Company should be allowed to earn more than its baseline ROE under the RIM Plan as a matter of fairness and maintaining a constructive regulatory environment;[30] and

WHEREAS, the Advisors recommend that the Council adopt an allowed-ROE of 8.93% for both electric and gas based on the comprehensive and persuasive testimony and multiple analyses of two expert witnesses in this proceeding;[31] and

WHEREAS, the Advisors' assert that their recommendation is based on the evaluation of market-based and accepted analytical methodologies that demonstrate that an 8.93% ROE represents a fair return to ENO;[32] and

WHEREAS, while an 8.93% ROE is in-line with the recommendations of the Intervenor witnesses (*i.e.*, 9.35%), the Advisors have pointed out that ENO's ROE proposal of 10.75% is an outlier among the other recommended ROEs in this proceeding;[33] and

WHEREAS, although the Company attempts to rely on numerous authorized ROEs in other jurisdictions to argue that the Advisors' and other Intervenors' recommendations are unreasonable, the Advisors argue that the ROEs cited in Mr. Hevert's testimony actually weakens ENO's argument for an authorized ROE of 10.75%.[34] The Advisors also argue that as evidenced in his own chart, the overwhelming majority of authorized ROEs represented in Mr. Hevert's testimony are significantly lower than ENO's requested ROE of 10.75% in this proceeding;[35] and

WHEREAS, ENO's claims that witness Hevert's "analysis indicated a range of 10.25% to 11.25% for equity investors' required ROE for investment in integrated electric utilities."[36] The

[30] Ex. No. ENO-2 at 27:14-16 (HSPM).
[31] Advisors' Initial Brief at 31.
[32] *Id.*
[33] Ex. No. ADV-8 at 18:14-19:4.
[34] Advisors' Initial Brief at 28; ENO-29 at 6, Chart 2.
[35] *Id.*
[36] ENO Initial Brief at 44.

Advisors assert that this claim is largely untrue.[37] As shown by the Advisors, in Mr. Hevert's testimony, he prepared no-less than five ROE analyses, of which only one supported an upper range of 10.75%;[38] and

WHEREAS, Advisors' witness Watson conducted a two-step DCF analysis which sought to estimate the implied ROE of utilities comparable to ENO as a proxy for ENO's own appropriate allowed-ROE, which itself cannot be directly measured;[39] and

WHEREAS, Mr. Watson's DCF analysis is also based on objective market data such as dividend yields and professional analysts' opinions as to growth factors.[40] The results of witness Watson's two-step DCF ROE analysis establish, among proxy companies and unadjusted for risk and flotation costs, a range of implied ROEs of 5.74% to 10.64% with a median implied ROE of 8.09%;[41] and

WHEREAS, Advisors' witness Proctor performed a CAPM analysis that identifies an allowed-ROE of 7.57% (unadjusted for risk and flotation costs), which is less than Mr. Watson's two-step DCF ROE analysis result;[42] and

WHEREAS, however, the Advisors' assert that as a DCF ROE analysis and a CAPM ROE analysis are based on different financial concepts (*i.e.*, DCF is based on dividend yields and growth factors, while CAPM is based on market returns and correlations therewith), the relative concurrence in results between these analyses has probative value for the Council in the instant proceeding;[43] and

[37] Reply Brief of the Advisors to the City Council of New Orleans at 4, Aug. 9, 2019 ("Advisors' Reply Brief").
[38] Ex. No. ADV-8 at 19-20, Table 2.
[39] Ex. No. ADV-7 at 13:1-7 (HSPM).
[40] *Id.* (HSPM).
[41] *Id.* at 44:1-4 (HSPM).
[42] *Id.* (HSPM).
[43] *Id.* at 44:14-45:2 (HSPM).

WHEREAS, according to the Advisors, Mr. Watson has reviewed Mr. Proctor's CAPM study, which is based on accepted methodologies and data, and he agrees with Mr. Proctor's analysis and results;[44] and

WHEREAS, Mr. Proctor discusses the ROE-related risk factors discussed by ENO witness, Mr. Hevert, and recommends the Council allow a risk-related ROE upward adjustment in this instant proceeding of 84 basis points;[45] and

WHEREAS, the Advisors adjusted their ROE findings for additional business risk ENO incurs largely as a result of its geographic location, its small size and its propensity to incur significant storm damage;[46] and

WHEREAS, according to the Advisors, Mr. Proctor's one standard-deviation adjustment methodology is objective and reflective of the variability of systemic risks among the Proxy Companies.[47] The Advisors also state that they specifically evaluated and addressed ENO's business risk[48] and Mr. Proctor's proposed 81 basis point adjustment was based on objective analysis and is reasonable, while ENO's arguments are general, subjective, and speculative;[49] and

WHEREAS, the Advisors made an additional adjustment to their recommended ROE for flotation costs which relate to incremental costs incurred from the issuance of common stock.[50] According to the Advisors, the costs are legitimately recoverable through utility rates either as a cost of equity or an operating expense;[51] and

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[44] *Id.* (HSPM).
[45] Ex. No. ADV-10 at 61:3-63:6 (HSPM).
[46] *Id.* at 61:3-10 (HSPM).
[47] Advisors' Initial Brief at 33.
[48] *Id.*
[49] *Id.*
[50] *Id.* at 34.
[51] *Id.*

WHEREAS, Mr. Watson presented the flotation cost-adjusted implied ROEs for the proxy companies, the median of such values is 8.12%, or approximately 3 basis points greater than the median of the non-flotation-adjusted proxy company implied ROEs.[52] His two-step DCF proxy company mean ROE analysis result of 8.09% plus these appropriate upward adjustments for business risks and flotation costs yields an allowed-ROE of 8.93%;[53] and

WHEREAS, the Advisors point out that the results of Mr. Proctor's CAPM ROE analysis are broadly consistent with those of Mr. Watson's two-step DCF ROE analysis and the Advisors recommend the Council take the results of Mr. Proctor's CAPM ROE analysis into account in the instant proceeding and adopt the Advisors' ROE recommendation;[54] and

WHEREAS, Intervenors, CCPUG and Air Products, also submitted testimony in this proceeding that included ROE recommendations to the Council; and

WHEREAS, CCPUG provided two methods of analysis for estimating a fair ROR for ENO, the DCF and CAPM analyses;[55] and

WHEREAS, based on these independent analyses, CCPUG concluded that a reasonable investor required ROE in the range of 8.70%-9.35% would be appropriate for ENO.[56] Employing these widely accepted financial methods for developing an ROE recommendation, CCPUG recommends that the Council adopt an ROE of 9.35%, which is on the high end of CCPUG's range;[57] and

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[52] Ex. No. ADV-7, Ex. No. BSW-4 (HSPM).
[53] Advisors' Initial Brief at 34.
[54] *Id.*
[55] Ex. No. CCPUG-3 at 15:15-24.
[56] *Id.* at 30:3-6.
[57] *Id.* at 30:6-7.

WHEREAS, with respect to evaluating and addressing ENO's business risk for purposes of making an ROE recommendation, CCPUG approached the issue of risk by acknowledging that ENO's business risk was considered by the credit rating agencies in their reports on ENO;[58] and

WHEREAS, according to CCPUG, Moody's and S&P mentioned these risks in various places in their reports which evaluated ENO's credit profile, its risk associated with severe weather, its small size, and the effect of the TCJA.[59] CCPUG also observed that with regard to customer diversity, the S&P report cited by CCPUG's witness Mr. Baudino noted that ENO's customer mix was a credit strength, not a weakness;[60] and

WHEREAS, CCPUG also argues that after assessing these risks, as well as credit strengths possessed by ENO, S&P assigned credit ratings to ENO that were consistent with the proxy group and with the electric utility industry in general and therefore CCPUG concluded that no additional risk premium is necessary for ENO relative to the proxy group;[61] and

WHEREAS, according to CCPUG, ENO's proposed 10.75% ROE far exceeds the average ROE awarded by regulators across the country in the last five years.[62] In fact, CCPUG urges, according to ENO's own data, its requested ROE of 10.75% is higher than all but one ROE granted by a regulator to an electric and gas utility over the last five years;[63] and

WHEREAS, Air Products also provided extensive ROE testimony in this case utilizing several financial models to estimate ENO's cost of common equity, including various forms of a DCF analysis, a Risk Premium analysis and a CAPM analysis similar to the financial models used by other ROE witnesses in the case;[64] and

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[58] Ex. No. CCPUG-3 at 46:22-47:1-10.
[59] *Id.*
[60] *Id.*
[61] *Id.*
[62] Initial Post-Hearing Brief of the Crescent City Power Users Group at 13, July 26, 2019 ("CCPUG Initial Brief").
[63] *Id.* citing Ex. ENO-29 at 6:3, Chart 2.
[64] Ex. No. AP-1 at 17:5-10.

WHEREAS, based on comprehensive studies utilizing multiple industry accepted financial models, Air Products concluded that an ROE in the range of 9.0%-9.7% would be appropriate for ENO.[65] A recommended ROE for ENO of 9.35% was supported by Air Products as a reasonable midpoint;[66] and

WHEREAS, Air Products' witness Christopher C. Walters undertook an extensive analysis of the regulated utility industry's access to capital, credit rating trends and outlooks, the overall trend in authorized ROEs for electric utilities throughout the country, and the impact that the Federal Reserve's monetary policy actions have had on the cost of capital;[67] and

WHEREAS, according to Air Products, Mr. Walters fully evaluated the market's perception of ENO's investment risk and considered ENO's proposed capital structure;[68] and

WHEREAS, Mr. Walters then used several cost of equity estimation methods performed on proxy group of publicly traded electric utility companies with comparable risk to ENO, including (1) a constant growth DCF Model using the consensus of analysts growth rate projections, (2) a constant growth rate DCF model using sustainable growth rate estimates, (3) a multi-stage DCF model, (4) a Risk Premium model, and (5) a CAPM analysis;[69] and

WHEREAS, according to Air Products, based on Mr. Walters' extensive analysis, he estimated that ENO's current market cost of equity is in the range of 9.0% and 9.7%, with a mid-point estimate of 9.35%;[70] and

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[65] *Id.* at 49:5-8.
[66] *Id.*
[67] *Id.* at 2:15-20.
[68] *Id.* at 3:1-3 and 17:11-19:5.
[69] *Id.* at 3:4-6 and 17:3-10.
[70] *Id.* at 3:6-8.

WHEREAS, Mr. Walters presented Direct Testimony & Schedules demonstrating that ROEs for electric and gas utilities have been reasonably stable well below 10.0% for about the last six years;[71] and

WHEREAS, Air Products states that during this period of declining ROEs, there has been significant improvement realized in the electric utility industry's overall credit quality and the ability of regulated utilities to access significant amounts of capital to support record amounts of capital investments over at least the last ten years;[72] and

WHEREAS, as set forth by Air Products, Mr. Walters' analysis and recommendation for a 9.35% ROE for ENO took into consideration ENO's specific investment risk and proposed capital structure;[73] and

WHEREAS, after performing several analyses utilizing multiple ROE financial models, witness Walters recommended an overall ROE for ENO of 9.35%;[74] and

WHEREAS, a 9.35% ROE is within the range of reasonable ROE recommendations made in this docket by three parties that provided expert testimony on this issue, including the Advisors, CCPUG, and Air Products; and

WHEREAS, ENO's argues that the Federal Energy Regulatory Commission ("FERC") has changed the law as to which financial modeling should be used in setting an ROE.[75] The Advisors contend that the Company plainly mischaracterizes FERC's statements on this issue.[76] The Advisors also responded that FERC does not, as ENO suggests, **require** the use of four financial models in setting an ROE that results in just and reasonable rates.[77] FERC has simply

[71] *Id.* at 4:4-10 and Figure 1.
[72] Air Products and Chemicals, Inc.'s Initial Post-Hearing Brief at 13, July 26, 2019 ("Air Products' Initial Brief").
[73] *Id.*
[74] *Id.* at 15.
[75] ENO Initial Brief at 38.
[76] Advisors' Reply Brief at 5.
[77] *Id.*

proposed that more than one model be used as opposed to relying on only one model.[78] The Advisors maintain that FERC has not issued any rule or requirement, but simply stated in that proceeding that it preferred to give consideration to the four financial models that were entered into the record of that case.[79] In fact, as noted by our Advisors, FERC has requested briefs from the parties in that proceeding to consider its proposal as it relates to financial modeling that should be used in evaluating and setting a ROE;[80] and

WHEREAS, the Advisors have submitted testimony from two expert witnesses in this case that do, in fact, include multiple sets of financial modeling data and results for the Council to consider.[81] Advisors' witness Mr. Watson employed the DCF analysis and Mr. Proctor used the Capital Asset Pricing Model CAPM analysis.[82] The Advisors state that both models are well accepted in the industry and they produce reliable results. Mr. Watson agreed with Mr. Proctor's CAPM modeling analyses and found that Mr. Proctor's results were reasonable.[83] Mr. Watson also recommends that the Council consider not only his DCF analysis, but also Mr. Proctor's analyses in making its decision to adopt a just and reasonable ROE.[84] Contrary to ENO's assertions, the Advisors utilized multiple models in conducting its ROE analyses and those modeling results fully support the Advisors' ROE recommendation;[85] and

WHEREAS, four ROE experts in this case, using multiple methodologies widely accepted in the utility industry, assert that ENO's proposed ROE is poorly supported by ENO's

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[78] *Ass'n of Businesses Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 165 FERC ¶ 61,118, at 34 (2018).
[79] Advisors' Reply Brief at 5.
[80] *Id.*
[81] *Id.*
[82] *Id.*
[83] Ex. No. ADV-7 at 45.
[84] *Id.* at 49.
[85] Advisors' Reply Brief at 5-6.

own testimony.[86] Mr. Hevert's updated DCF analyses in his rebuttal testimony produced results ranging from 8.34%-10.38% which clearly does not support his recommended 10.75% ROE.[87] Similarly, Mr. Hevert's revised CAPM ROE analyses presented in his rebuttal testimony produced a substantially lower range of results, from 8.25%-11.34%, placing his recommended 10.75% near the top of his revised range of results;[88] and

WHEREAS, the Council's Advisors have shown that ENO's updated analyses provide further support for the Advisors' and Intervenors' arguments that the Company's requested 10.75% ROE is unreasonable and not supported by the preponderance of evidence in the instant docket;[89] and

WHEREAS, the Council finds that the testimony provided by the Advisors' ROE witnesses, which was based on the utilization of more than one industry accepted financial method is well supported and convincing evidence in this proceeding; and

WHEREAS, the Council finds that the 8.93% ROE recommendation made by the Advisors is reasonable and supported by the Advisors analysis in this case; and

WHEREAS, the Council also finds that the ROE testimony provided by CCPUG and Air Products in this case, which was also based on the utilization of multiple industry accepted financial methods is similarly well supported and convincing; and

WHEREAS, the Council finds that the 9.35% ROE recommendation made by CCPUG and Air Products is also reasonable and supported by the analysis presented in this case; and

[86] Advisors' Initial Brief at 28; Air Products' Initial Brief at 16; CCPUG Initial Brief at 32-35.
[87] Ex. No. ENO-29 at 144:1.
[88] *Id.*
[89] Advisors' Initial Brief at 28-29.

WHEREAS, the Council also acknowledges that the 9.35% ROE recommended by CCPUG and Air Products in this case is also within the scope of ROEs supported by Advisors' witness Watson's analysis which resulted in a range of implied ROEs of 5.74% to 10.64%; and

WHEREAS, the Council agrees with the Advisors, CCPUG and Air Products that ENO's proposed ROE of 10.75% is not convincingly supported by ENO's own testimony; and

WHEREAS, the Council agrees with the Advisors and Intervenors that ENO's updated analyses provide further support for the Advisors' and Intervenors' arguments that the Company's requested 10.75% ROE is unreasonably high and not supported by the preponderance of evidence in the instant proceeding; and

WHEREAS, considering all of the testimony and evidence presented related to the appropriate ROE for ENO in this proceeding, the Council finds that ENO's proposed ROE of 10.75% should be rejected and an ROE of 9.35% is reasonable and should be adopted; and

EQUITY RATIO

WHEREAS, ENO has proposed that its actual equity ratio be employed for ratemaking purposes in this proceeding.[90] ENO witness Orlando Todd submitted testimony that ENO projects its capital structure as of December 31, 2018 will consist of 52.2% common equity, with the rest consisting of long-term debt;[91] and

WHEREAS, the Company used this estimated 52.2% equity ratio to calculate its WACC and revenue requirement in its cost of service studies in this proceeding;[92] and

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[90] *Id.* at 35.
[91] Ex. No. ENO-33 at 14:13-14.
[92] *Id.*

WHEREAS, the Advisors submitted testimony contending that ENO's proposed capital structure, if adopted, would constitute inappropriate double leveraging;[93] and

WHEREAS, according to the Advisors, a useful meaning of "double leverage" for the purposes of the instant proceeding is the practice of maintaining a significantly higher common equity ratio at the utility operating company level (*i.e.*, ENO) than is maintained at the highest corporate level ultimately owning the utility (*i.e.*, Entergy Corp.);[94] and

WHEREAS, because the return on a utility's investment component of its revenue requirement is customarily based on its WACC and the rate of the ROE component of WACC is typically at a higher rate than those of the debt components (especially on a pre-tax basis), our Advisors assert that a high common equity ratio tends to increase a utility's WACC, and revenue requirement;[95] and

WHEREAS, our Advisors further argue that the effect of a utility that engages in double leverage is as if it borrows money at the top corporate level and places that money into its utility subsidiaries as common equity providing a potential return which is likely greater than its original borrowed cost;[96] and

WHEREAS, based on our Advisors' analysis, ENO's equity ratio is greater than those of Entergy Corp. as well as the average of the other Entergy Operating Companies ("EOCs");[97] and

WHEREAS, according to testimony provided by our Advisors, ENO's proposed equity ratio of 52.2% is 18.1% higher than that of Entergy Corp. as of December 31, 2018, while the average equity ratio of the other EOCs projected as of December 31, 2018, is only 15.5% higher

93 Ex. No. ADV-7 at 51:1-4 (HSPM).
94 *Id.* (HSPM).
95 *Id.* at 51:4-8 (HSPM).
96 *Id.* at 51:8-11 (HSPM).
97 *Id.* at 50:5-6 (HSPM).

than that of Entergy Corp.[98] As such, the revenue requirement effect of ENO's double leverage on New Orleans ratepayers is more pronounced than that for the average ratepayer of the other EOCs;[99] and

WHEREAS, ENO claims that that the Advisors have misinterpreted the other Entergy Operating Companies' equity ratios and argues that the Advisors' comparison of ENO's proposed equity ratio to the other Entergy Operating Companies "sheds no light on the issue;"[100] and

WHEREAS, despite ENO's claims to the contrary, the Advisors argue that comparing ENO's capital structure to that of the other EOCs is important for the Council's consideration because such a comparison serves as a guide for assessing the reasonableness of ENO's capital structure;[101] and

WHEREAS, analyzing these comparisons, according to the Advisors, provides the revenue requirement effect of ENO's proposed capital structure as compared to that of the other EOCs.[102] In fact, employing ENO's Period II External Models and changing ENO's equity ratio to be consistent with the non-ENO EOCs' average equity ratio of 49.6% as opposed to ENO's proposed 52.2% yields a $1.5 million reduction in electric revenue and a $0.3 million reduction in gas revenue;[103] and

WHEREAS, considering the arguments set forth by the Advisors regarding double leverage, the significance of ENO's equity ratio being higher than that of the average of the other EOCs and the impact of ENO's proposed equity ratio on ratepayers, the Advisors recommend that

[98] *Id.* at 53:1-3 (HSPM).
[99] *Id.* at 53:3-5 (HSPM).
[100] ENO's Initial Brief at 60.
[101] Advisors' Initial Brief at 36.
[102] Advisors' Initial Brief at 36; Ex. No. ADV-7 at 52:20-53:5 (HSPM).
[103] Advisors' Initial Brief at 37; Ex. No. ADV-7 at 53:8-11 (HSPM).

the Council adopt an equity ratio of 50% in the instant proceeding for setting ENO's electric and gas rates;[104] and

WHEREAS, for setting rates as part of any FRP evaluations the Council approves in this case, the Advisors believe the Council should employ an equity ratio equal to the lesser of (a) ENO's then actual equity ratio properly excluding the effects of securitization bonds and cash, and (b) 50%;[105] and

WHEREAS, CCPUG asserts that ENO's capital structure must include short-term debt, because (a) it is abundantly available to ENO, (b) ENO routinely uses short-term debt for its operations, and (c) it is the lower-cost option for capital as compared to long-term debt and ENO's requested 10.75% ROE;[106] and

WHEREAS, according to CCPUG, ENO has available two sources of short-term debt.[107] The first source is the internal Entergy Money Pool whereby Entergy operating utilities that have a surplus of cash deposit it into the Money Pool and the Entergy operating utilities that need cash borrow it from the Money Pool.[108] The second source is an external Company-specific credit facility of $25 million, which includes fronting commitments of up to $10 million for the issuance of letters of credit against the borrowing capacity of the facility.[109] CCPUG also claims that ENO may borrow up to $150 million from the Entergy Money Pool, other internal short-term borrowing arrangements, and external sources pursuant to FERC authorization;[110] and

[104] Advisors' Initial Brief at 37; Ex. No. ADV-7 at 55:16-18.
[105] Advisors' Initial Brief at 37; Ex. No. ADV-7 at 55:16-56-1.
[106] Reply Post-Hearing Brief of the Crescent City Power Users Group at 21, Aug. 9, 2019 ("CCPUG Reply Brief").
[107] CCPUG Initial Brief at 95.
[108] *Id.*
[109] *Id.*
[110] *Id.*

WHEREAS, Mr. Kollen explained that ENO should use some amount of short-term debt in lieu of long-term debt and common equity to reduce its cost of capital and its revenue requirements;[111] and

WHEREAS, CCPUG witness Mr. Kollen testified it is not reasonable for ENO to exclude short-term debt from the capital structure and cost of capital, especially since short-term debt is available to ENO at a fraction of the cost of long-term debt and common equity;[112] and

WHEREAS, ENO relies heavily on a Louisiana Supreme Court decision to support its unreasonably high capital structure proposal;[113] and

WHEREAS, according to the Advisors, ENO claims that the Court in *South Central Bell* held very narrowly that the utility "'is entitled to have its rates fixed on the basis of its actual cost of capital under its existing capital structure'" absent a finding "'that the actual capital structure of the utility resulted from unreasonable or imprudent investments;'"[114] and

WHEREAS, the Company also claims that the Advisors have "not pointed to a single instance that the Company made an unreasonable investment or financing decision."[115] However, ENO's strict interpretation of the Court's ruling on this issue is erroneous. *South Central Bell* plainly states that if the regulator finds that the utility's proposed capital structure is unreasonable, it may adopt a reasonable alternative;[116] and

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[111] CCPUG Initial Brief at 96.
[112] *Id.* at 96-97, citing Ex. CCPUG-1 at 39:1-5.
[113] Ex. No. ENO-3 at 24:5-6; Ex. No. ENO-4 at 15:17-19; citing *S. Cent. Bell Tel Co. v. Louisiana Pub. Serv. Comm'n*, 594 So. 2d 357.
[114] Ex. No. ENO-4 at 15:19-16-1; citing *S. Cent. Bell Tel Co. v. Louisiana Pub. Serv. Comm'n*, 594 So. 2d 357.
[115] *Id.* at 16:1-2.
[116] *S. Cent. Bell Tel. Co.* v. *Louisiana Pub. Serv. Comm'n,* 594 So. 2d at 363.

WHEREAS, specifically, the Court stated, "we conclude … that the Commission must find a utility's capital structure imprudent or unreasonable before disregarding it in ratemaking;[117] and

WHEREAS, the Advisors argue that the unreasonableness is, thus, not limited to investments made by the utility.[118] The unreasonableness that the Advisors explain primarily from, among other reasons, the effect of double leverage that exists as a result of Entergy Corporation having a significantly lower equity ratio than that of its subsidiary, ENO;[119] and

WHEREAS, CCPUG also maintains that ENO's proposed capital structure is unreasonable because it fails to include short-term debt;[120] and

WHEREAS, a later Louisiana Supreme Court case, cited by the Advisors, supports the Advisors' and CCPUG's argument regarding the regulator's ability to set aside the utility's unreasonable capital structure in favor of a more equitable alternative;[121] and

WHEREAS, in the *Entergy Gulf States* case, the utility used the net proceeds of debt to determine the ratio of debt to equity capital in its capital structure.[122] The Commission, however, adjusted the Company's filing by reducing its average weighted cost of capital to reflect the gross proceeds of debt in the company's capital structure.[123] The sole capital structure problem presented to the Court was whether the Commission acted arbitrarily or capriciously by including the gross proceeds of debt, rather than the net proceeds of debt, in the Company's capital

[117] *Id.*
[118] Advisors' Initial Brief at 38.
[119] *Id.*
[120] CCPUG Reply Brief at 21.
[121] *Entergy Gulf States, Inc. v. Louisiana Pub. Serv. Comm'n*, 730 So. 2d 890 (La. 1999).
[122] *Id.* at 915-16.
[123] *Id.*

structure.[124] In affirming the regulator's authority to adopt a different capital structure than the one proposed by the utility, the Court stated:

> The right of commissions to consider [capital structure] in setting rates cannot be questioned, since a commission has an obligation to protect the consumer from excessive wages, excessive pension provisions, excessive prices for purchased materials and supplies, and other such things, including excessive costs of capital[125]

and

WHEREAS, the Court also clearly found, in affirming the regulator's adjustment to the utility's proposed capital structure, that the utility had not demonstrated that the Commission had set unjust or unreasonable rates.[126] Orders of utility regulators in the State of Louisiana are "entitled to great weight" and "they should not be overturned absent a showing of arbitrariness, capriciousness, or abuse of authority by the Commission."[127] Courts should also "be reluctant to substitute their own views for those of the expert body charged with the legislative function of rate-making;"[128] and

WHEREAS, the Advisors urge the Council to note that ENO routinely recommends utilizing a hypothetical capital structure in requesting rate recovery of costs incurred by the Company.[129] For example, the Company acknowledged in this proceeding that in Council Docket No. UD-15-01, ENO's own witness recommended a hypothetical capital structure of 50% be used for ratemaking purposes for the recovery of costs associated with the acquisition of Union Power Block #1.[130] According to the Advisors, ENO also employed an "Assumed 50% Common Equity" even though ENO's actual equity ratio was not 50% in Council Docket No. UD-17-02 related to

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[124] *Id.*
[125] *Id.* at 917, citing Paul J. Garfield & Wallace F. Lovejoy, Public Utility Economics at 130 (1964).
[126] *Id.*
[127] *Id.* at 897.
[128] *Id.*
[129] Advisors' Initial Brief at 39.
[130] City Council Hearing Transcript, 120:5-9 (June 20, 2019).

the Company's Gas Infrastructure Rebuild Program.[131] The Advisors also point out that, in these instances, when recommended by the Company, a 50% equity ratio was not only reasonable but specifically proposed by ENO is its requests for cost recovery;[132] and

WHEREAS, the Council agrees with the Advisors and CCPUG that ENO's proposed equity ratio is unreasonable; and

WHEREAS, the Council also agrees that an unreasonably high equity ratio would constitute an inappropriate amount of double leveraging, result in an unreasonably higher equity ratio than those of Entergy Corp. as well as an equity ratio higher than the average of the other EOCs; and

WHEREAS, the Council also agrees with the Advisors and CCPUG that Louisiana Law allows a regulator to set aside the utility's unreasonable capital structure in favor of a more equitable alternative; and

WHEREAS, the Council finds that the inclusion of short-term debt in the calculation of ENO's allowed ROR (*i.e.*, WACC) is contrary to established Council ratemaking practices and is not supported by the preponderance of evidence in the instant proceeding; and

WHEREAS, as shown by the Advisors and CCPUG in sworn testimony and supporting analyses provided in this proceeding, ENO's proposed capital structure is unreasonably high and the Council rejects ENO's proposal in favor of a more reasonable equity ratio of the lesser of 50% or ENO's actual equity ratio for the purposes of this instant proceeding and for the FRP evaluations ordered in this resolution; and

[131] Ex. No. ADV-7 at 54:18-55:3 (HSPM).
[132] Advisors' Initial Brief at 39.

DEPRECIATION RATES

WHEREAS, ENO's witness Donald J. Clayton sponsored new depreciation rates based on a study conducted by Tangibl, LLC, which was carefully reviewed by the Council's Advisors.[133] The study states that it employs accepted depreciation study methodologies to create what is commonly referred to as *Iowa Curve* factors taking into account survivor curves, expected retirement dates, and salvage factors.[134] Mr. Clayton reports that ENO's proposed depreciation rates would increase ENO's depreciation expense by $2.5 million and $0.1 million for electric and gas respectively as compared to retaining ENO's currently approved depreciation rates;[135] and

WHEREAS, the Advisors reviewed Mr. Clayton's testimony and indicated that ENO's proposed depreciation rates are based on accepted analytical methodologies and represent an incremental change to depreciation rates that ENO reports as having been in effect since 1980 and 2009 for electric and gas respectively.[136] Further, as depreciation represents recovery of ENO's investments in plant, ENO's requested overall increase in depreciation rates serves to slightly hasten the decline in ENO's appropriate dollar return on rate base.[137] ENO's proposed depreciation rates also appropriately provide for removing stranded costs (*i.e.*, related to a general plant reserve deficiency) from rate base over a 10-year period.[138] Accordingly, the Advisors recommended the Council adopt ENO's proposed new depreciation rates;[139] and

WHEREAS, CCPUG argues that ENO's proposed service lives for Union Power Station, Power Block 1 ("UPS") and New Orleans Power Station ("NOPS") are unsupported and

[133] Ex. No. ADV-7 at 60:3-4 (HSPM).
[134] *Id.* at 60:4-6 (HSPM).
[135] Ex. No. ENO-35 at 16, Comparison table.
[136] Ex. No. ADV-7 at 61:7-17 (HSPM).
[137] *Id.* (HSPM).
[138] *Id.* (HSPM).
[139] *Id.* (HSPM).

unreasonably short.[140] In doing to, according to CCPUG, ENO seeks to accelerate the recovery of depreciation on these plants and to unnecessarily inflate its revenue requirement, respectively.[141] CCPUG urges the Council to reject ENO's unrealistically short service lives and the related depreciation expense and instead use a 40-year service life for UPS, and change the first-year revenue requirement to reflect a 50-year service life for NOPS (rather than a 30-year life);[142] and

WHEREAS, CCUPG witness Mr. Kollen examined publicly-available information from the Energy Information Administration which showed that similar combined cycle units were in service for 40 to 50 years before their retirements;[143] and

WHEREAS, ENO witness Mr. Clayton admitted that determining the service life of a generating unit for depreciation purposes and estimating salvage value is not an exact science.[144] Also according to Mr. Clayton, the retirement date of a plant is an important factor in determining its service life;[145] and

WHEREAS, the decision whether to retire a plant is driven by multiple factors according to ENO, such as repair costs, location of the plant, and environmental issues.[146] However, ENO provided the retirement date for UPS to Mr. Clayton, but did not provide him with any studies, analyses, or empirical data supporting that decision;[147] and

WHEREAS, according to CCPUG, Mr. Clayton attempted to dispute Mr. Kollen's use of similar plants to establish the service life for UPS by claiming that, because UPS (a combined cycle

[140] CCPUG Initial Brief at 64.
[141] *Id.*
[142] *Id.*
[143] Ex. No. CCPUG-1 at 29:7-30:10.
[144] City Council Hearing Transcript, 138:23-139:5 (June 18, 2019).
[145] *Id.*, 140:3-11.
[146] *Id.*, 140:3-11.
[147] *Id.*, 141:20-142:7.

gas plant) was constructed after 2000, that the combined cycle gas plants Mr. Kollen referenced, which were constructed prior to 2000, were not comparable;[148] and

WHEREAS, however, CCPUG points out that Mr. Clayton offers no proof whatsoever that UPS' service life will, most likely, be shorter than a pre-2000 combined cycle plant;[149] and

WHEREAS, according to testimony provided by ENO, a major component replacement can extend the service life of a generating unit.[150] Mr. Breedlove opined that the combustion turbine rotors are a "major component" of UPS and have an estimated service life of roughly 19 years.[151] However, Mr. Breedlove did not recommend a 19-year service life for UPS; he recommended a 30-year life.[152] CCPUG asserts that to reach a 30-year life, UPS will most likely have to replace its combustion turbine rotors.[153] Although the service life of a plant is not determined by any one component, in CCPUG's view, the combustion turbine rotors are a major component that can greatly extend the life of the plant;[154] and

WHEREAS, Mr. Kollen recommends the use of a 40-year service life for UPS and estimates that the financial effect his recommendation would be a $5.029 million reduction in ENO's electric base revenue requirement;[155] and

WHEREAS, in addition, CCPUG claims that ENO has no experience with retirements or net salvage value for UPS means that its actual experience is 0% net salvage[156] not negative 8% as ENO proposes. Mr. Kollen calculated that the effect of employing a 0% net salvage value for

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148 *Id.*, 148:5-149:5.
149 CCPUG Initial Brief at 66.
150 Ex. ENO-48 at 5:4-12.
151 *Id.* at 5:1-18; *see also*, City Council Hearing Transcript, 71:1-72:15 (June 19, 2019).
152 CCPUG Initial Brief at 66.
153 *Id.*
154 *Id.*
155 Ex. No. CCPUG-1 at 30:17-18.
156 *Id.* at 31:7-15.

UPS for depreciation purposes would lead to a reduction of $0.628 million in the electric base revenue requirement;[157] and

WHEREAS, with respect to NOPS, Mr. Kollen investigated publicly-available information on retirements of peaking unit plants, like NOPS, and found that similar units have been in operation for nearly 50 years or more;[158] and

WHEREAS, CCPUG asserts that the utility is made whole over time, because it will collect all of its depreciation, including consideration for salvage value; thus, the issue is whether ENO collects these costs over 30 years or 40 years or 50 years;[159] and

WHEREAS, Mr. Kollen recommends that a 9.35% ROE be used in the E-FRP, the first-year revenue requirement be reduced to reflect a 50-year service life, and ENO be ordered to reduce the revenue requirement for NOPS each year to reflect an additional year of depreciation and deferred income tax expense;[160] and

WHEREAS, Mr. Kollen then calculated the effect of his recommendations and concludes the first-year revenue requirement for NOPS should be reduced by $4.073 million;[161] and

WHEREAS, the Council believes the CCPUG has made a compelling argument for extending the service lives for UPS and NOPS for the purposes of depreciation; and

WHEREAS, CCPUG has provided significant evidence in the record establishing that the service lives for these particular types of generating technology is considerably longer than ENO has proposed for purposes of calculating depreciation rates; and

[157] *Id.* at 32:22-23.
[158] *Id.* at 47:1-19.
[159] CCPUG Initial Brief at 68.
[160] Ex. No. CCPUG-1 at 48:6-13.
[161] *Id.* at 48:15-20.

WHEREAS, the Council believes that ENO's ratepayers will benefit from lower rates if the utility utilizes longer service life estimates for calculating depreciation rates; and

WHEREAS, the Council finds that CCPUG's recommended 40-year service life for UPS and 50-year service life for NOPS shall be used by ENO in calculating depreciation rates in this proceeding; and

TAX ISSUES

(1) *FIN 48 ADIT Liabilities*

WHEREAS, the Financial Accounting Standards Board's Interpretation No. 48[162] ("FIN 48") provides an interpretation of FAS No. 109 regarding the accounting for uncertainty in income taxes recognized in financial statements;[163] and

WHEREAS, in applying FIN 48, a determination is made by the taxpayer for specific transactions as to whether it is more likely than not that a tax position will be sustained upon examination, including resolution of appeals or litigation processes, based on the technical merits of the position. Then the tax position is measured at the largest amount of benefit that is greater than 50% likely to be realized upon ultimate settlement. This amount is recognized as an Accumulated Deferred Income Tax ("ADIT") liability for financial reporting purposes;[164] and

WHEREAS, ENO, through complying with normalization rules, records Deferred Income Tax ("DIT") expense that is part of ENO's cost of service and is recoverable in utility rates;[165] and

WHEREAS, ENO has proposed to remove from its electric and gas rate bases, the portion of various ADIT liabilities that it states are unlikely to produce cost-free capital due to the

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[162] Financial Accounting Series No. 281-B, June 2006, FASB Interpretation No. 48 of the FASB of the Financial Accounting Foundation.
[163] Advisors' Initial Brief at 40.
[164] *Id.* at 40-41.
[165] *Id.* at 42.

aggressive tax positions taken by the Company in its filings with federal and state taxing authorities (FIN 48 ADIT),[166] with the specific proposed amounts by account to be so excluded;[167] and

WHEREAS, the Advisors disagree with ENO's proposed ratemaking treatment of FIN 48 ADIT liabilities. The Advisors evaluated the FIN 48 ratemaking issues in this proceeding in a two pronged approach: (1) how is the financial risk shared between ratepayers and shareholders with respect to the uncertainty of the income tax position taken by ENO; and (2) making the correct adjustment required for ratemaking purposes. With respect to issue of financial risk, the Advisors disagree with ENO's adjustment to eliminate FIN 48 ADIT liability balances from rate base for its electric and gas operations;[168] and

WHEREAS, the Advisors argue that ENO's recording of DIT expense and including it in its cost of service provides ENO a cost-free loan from the ratepayers which requires that the related FIN 48 ADIT liability also be included in rate base;[169] and

WHEREAS, ENO argues that its aggressive tax positions underlying the FIN 48 ADIT essentially have no effect on the level of income tax expense included in ENO's revenue requirement in its Period II Electric and Gas Cost of Service Studies, and a result, when considering income tax expense, a utility's customers are indifferent as to whether a utility uses aggressive tax positions on its tax return;[170] and

WHEREAS, ENO argues that FIN 48 ADIT is not cost-free capital in that ENO accrues interest expense on its aggressive tax positions, and that interest expense is borne by ENO and not recovered by ENO from customers in rates;[171] and

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[166] *Id.* at 41.
[167] Ex. No. ENO-1 at 71, Table 3 (HSPM).
[168] Advisors' Initial Brief at 41-42.
[169] *Id.* at 42.
[170] ENO Initial Brief at 147.
[171] *Id.*

WHEREAS, the Advisors support ENO's recovery of prudently incurred interest expense attributed to ENO paying interest for tax underpayments to the federal government related to prudent FIN 48 positions it takes;[172] and

WHEREAS, the CCPUG recommends that that the Council authorize ENO to record a regulatory asset and seek recovery in a future ratemaking proceeding for the interest paid to the IRS related to FIN 48 ADIT calculated from the date when rates are reset in this proceeding;[173] and

WHEREAS, the CCPUG agrees with the Advisors that ENO's proposed treatment of FIN 48 amounts to a cost-free loan from the ratepayers to ENO and that in this way, ENO pockets the carrying charge value on the savings that were funded by ratepayers. The CCPUG argues that the Council should subtract the FIN 48 ADIT amounts from rate base;[174] and

WHEREAS, the Advisors make certain recommendations regarding the recoverability of DIT in the event the Council approves ENO's proposal to exclude FIN 48 ADIT from rate base; and

WHEREAS, the Council agrees with ENO that its aggressive tax positions underlying FIN 48 ADIT have no effect on its income tax expense as presented in its Period II electric and gas cost of service studies in the instant proceeding; and

WHEREAS, ENO's argument that its aggressive tax positions underlying FIN 48 ADIT having no effect on income tax expense is supportive of its proposal to exclude FIN 48 ADIT from its rate base is unpersuasive, and the Council agrees with the Advisors and the CCPUG that such

[172] Ex. No. ADV-13 at 63.
[173] Ex. No. CCPUG-1 at 26.
[174] CCPUG Initial Brief at 38.

proposed treatment provides ENO a cost-free loan from the ratepayers in which ENO pockets the carrying charge value of savings funded by ratepayers; and

WHEREAS, the Council finds that FIN 48 ADIT liabilities should be included in ENO's rate base; and

WHEREAS, any discussion as to the appropriate ratemaking treatment of DIT in the event FIN 48 ADIT liabilities are excluded from ENO's rate base is moot; and

WHEREAS, the Council finds that the FIN 48 ADIT liabilities ENO has proposed to exclude from its gas and electric rate bases as part of its electric and gas Period II cost of service studies in the Revised Application[175] should be included in ENO's gas and electric rate bases; and

WHEREAS, the Council agrees that prudently undertaken aggressive tax positions may involve prudently incurred related costs such as interest accruals or payments related to the period starting with the effective date of rates established herein; and

WHEREAS, the Council generally agrees that the CCPUG's recommended treatment of prudently incurred interest payments related to FIN 48 ADIT through a regulatory asset is reasonable, although the Council notes that it would authorize the creation of any such regulatory asset; and

WHEREAS, in future retail rate actions before the Council, ENO may propose for Council consideration a ratemaking mechanism for the recovery of prudently incurred costs related to FIN 48 ADIT liabilities that are included in ENO's rate base, such as interest accrued or paid, and related to the period starting with the effective date of rates established herein; and

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[175] Ex. No. ENO-1 at 71, Table 3 (HSPM).

(2) *NOLCF ADIT Assets*

WHEREAS, in any given year, when a company has more income tax deductions than taxable income, the excess of the income tax deductions over taxable income is called a net operating loss ("NOL"). This NOL represents a future income tax benefit that ENO may use, and is referred to as a net operating loss carry forward ("NOLCF") and recorded as an ADIT asset;[176] and

WHEREAS, ENO proposes to include NOLCF ADIT asset balances attributable to accelerated tax depreciation in its rate base, citing two Private Letter Rulings ("PLR") that ENO argues explain the income tax normalization rules that require the inclusion in its rate base of the NOLCF ADIT asset balance attributable to accelerated tax depreciation;[177] and

WHEREAS, ENO argues that the two PLRs it cites explain that the NOLCF ADIT asset balance must be included in ENO's rate base to offset the credit ADIT by the amount for which no cost-free capital was received, otherwise a normalization violation of the IRS's income tax rules could cause the IRS to prohibit ENO from using accelerated tax depreciation on its income tax return;[178] and

WHEREAS, through a response to discovery propounded upon ENO by the Advisors in the instant proceeding, ENO revised downward the amount of NOLCF ADIT it proposes to include in its electric and gas rate bases in the instant proceeding;[179] and

WHEREAS, the Advisors argue that the Council should not rely on the conclusions drawn in the two PLRs cited by ENO because it is impossible to compare the facts, as presented by the

[176] Advisors' Initial Brief at 45.
[177] *Id.* at 46.
[178] *Id.*
[179] ENO Initial Brief at 169; Post-Hearing Reply Brief of Entergy New Orleans, LLC at 120, Aug. 9, 2019 ("ENO Reply Brief").

taxpayers in those cases, to this case as presented by ENO and note that there is no indication that the taxpayers that requested the PLRs stated that deferred income tax expense was reflected in their rates in prior periods, and without the benefit of this critical information, the Council is unable to rely on these PLRs as a basis for approving ENO's proposed ratemaking treatment of NOLCF ADIT asset balances;[180] and

WHEREAS, the Advisors also argue that, even if ENO's cited PLRs may be relied upon by the Council in the instant proceeding, ENO's NOLCF ADIT asset is not attributable to accelerated depreciation because the NOL cannot be tied to the excess depreciation over straight-line depreciation;[181] and

WHEREAS, the Advisors further argue that ENO's total income tax expense, for financial accounting purposes, includes a current provision payable to the government based on income tax law and a deferred provision based on financial accounting standards, and as such ENO was allowed recovery of all tax expenses, current and deferred, which constitutes taxable revenue;[182] and

WHEREAS, the Advisors argue that due to ENO's allowed recovery of all tax expenses, the NOL carried forward during the previous periods was less than it otherwise would have been by an amount equal to the deferred income taxes which were not paid to the government but were collected from ratepayers;[183] and

WHEREAS, the Advisors state that none of ENO's NOLCF ADIT assets are directly "attributable" to income tax timing differences, or the attributable balance of such is zero, and they

[180] Advisors' Initial Brief at 46-47.
[181] *Id.* at 48.
[182] *Id.*
[183] *Id.* at 48-49.

recommend the Council deny ENO's proposal to add NOLCF ADIT asset balances to its rate bases;[184] and

WHEREAS, the Advisors discussed and made recommendations as to Council regulatory treatment of DIT should the Council allow ENO to include NOLCF ADIT asset balances in its rate bases;[185] and

WHEREAS, the Council finds persuasive the Advisors' argument that ENO has been allowed recovery of all of its book tax expenses, including DIT related to accelerated depreciation, and as such, the NOLCF ADIT asset balance attributable to accelerated depreciation is zero; and

WHEREAS, as the Council herein finds that any NOLCF ADIT asset amount properly includable in ENO's rate bases in the instant proceeding is zero, further consideration as to the probative value of ENO's two cited PLRs is not necessary at this time and any discussion of alternate regulatory treatment is moot; and

(3) *Rider SSCO ADIT*

WHEREAS, the Advisors recommend the Council direct ENO to employ its then current WACC when setting Rider SSCO's rates,[186] a recommendation that is not opposed by ENO[187] or any party to the proceeding; and

WHEREAS, the Council finds that ENO should employ its then current WACC, reflective of the provisions for a cap on ENO's equity ratio therein as ordered herein, when periodically setting Rider SSCO's rate; and

[184] *Id.* at 49.
[185] *Id.* at 46.
[186] *Id.* at 149.
[187] ENO Reply Brief at 115.

WHEREAS, as part of ENO's rebuttal testimony, ENO stated that in its Revised Application, it failed to make the entry to remove the balance of ADIT associated with Rider SSCO from the rate base in its cost of service studies,[188] as noted in ENO's Post Hearing Brief;[189] and

WHEREAS, at Hearing, ENO offered a dollar revenue requirement effect of its stated failure to remove ADIT associated with Rider SSCO from its rate base,[190] as noted in ENO's Post Hearing Brief;[191] and

WHEREAS, per the procedural schedule in the instant proceeding the Council-authorized period of discovery had expired prior to the Hearing; and

WHEREAS, the Council approved a procedural schedule in the instant proceeding calculated to afford parties to carefully inspect, validate, and rebut as necessary the proposals and claims of other parties; and

WHEREAS, due to the timing of ENO's statements and disclosures, parties to the instant proceeding were not afforded the opportunity to inspect, validate, propound discovery related to, or rebut ENO's claim as to the dollar amount of the revenue requirement effect of any such failure; and

WHEREAS, the Council finds that evidence in the Administrative Record is insufficient to support setting rates reflective of ENO's stated dollar revenue requirement effect[192] related to ENO's stated failure to remove ADIT related to Rider SSCO from its rate base; and

[188] Ex. No. ENO-3 at 42-43.
[189] ENO Initial Brief at 170.
[190] City Council Hearing Transcript at 178-179 (June 17, 2019).
[191] ENO Initial Brief at 170.
[192] City Council Hearing Transcript at 178-179 (June 17, 2019).

(4) *ADIT Related to Stranded Plant*

WHEREAS, as part of the AMI deployment ENO must retire certain related existing plant, such as meters, prior to its full recovery through depreciation ("Stranded Plant");[193] and

WHEREAS, the retirement of this Stranded Plant is associated with ENO's per-book recording of ADIT liabilities; and

WHEREAS, the economic benefit to ENO of Stranded Plant ADIT in the form of cost-free capital is undisputed;[194] and

WHEREAS, in its Revised Application, ENO removed ADIT related to Stranded Plant from rate base;[195] and

WHEREAS, the Advisors argue that ENO's rates should reflect the economic benefit it enjoys due to cost-free capital, such as ADIT related to Stranded Plant;[196] and

WHEREAS, ENO argues that allowing ADIT related to Stranded Plant in its rate base could constitute a "potential violation" of IRS normalization rules;[197] and

WHEREAS, out of an abundance of caution regarding ENO's argument of a "potential violation" of IRS rules, the Advisors recommend the Council recognize the benefit to ENO of cost-free capital and direct ENO to create regulatory liabilities;[198] and

WHEREAS, ENO argues that the Council's creating a regulatory liability to recognize ENO's economic benefit related to cost-free capital amounts to "changing the name of the reserve or the book account of the reserve," and does not negate the "potential" IRS normalization rules violation;[199] and

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[193] Advisors' Initial Brief at 147.
[194] *Id.* at 148.
[195] Ex. No. ADV-6 at 57:1-3, Advisors Initial Brief at 147.
[196] *Id.*
[197] *Id.*
[198] *Id.*
[199] ENO Reply Brief at 74.

WHEREAS, ENO states that the Council should reject the Advisors' recommendation to create a regulatory liability as it would result in a normalization violation and harm customers;[200] and

WHEREAS, the Council finds nothing in the record demonstrating that the Advisors are recommending the Council "change the name" or "book account" of any reserve; and

WHEREAS, the Council agrees that the Advisors' recommendation to create a regulatory liability is to reflect the undisputed economic benefit to ENO of cost-free capital through Stranded Plant ADIT; and

WHEREAS, the Council notes its authority to set rates based in part on allowing ENO the reasonable opportunity to recover its prudently incurred costs; and

WHEREAS, the Council notes its authority to create regulatory liabilities as part of its ratemaking authority; and

WHEREAS, the Council finds that ENO should record a regulatory liability reflective of the economic benefit of cost-free capital through Stranded Plant ADIT, with such regulatory liability being a component of ENO's electric and gas rate bases; and

RESTRICTED STOCK INCENTIVE PLAN

WHEREAS, the Advisors audited ENO's affiliate transactions, and for the most part, found that ENO had properly treated its Billing Adjustments related thereto, with one exception.[201] Based on the Advisors' review of ENO's affiliated transactions during the test-year period, the Advisors recommend that the cost of ENO's Restricted Stock Incentive Plan ("Plan") should not be recovered in rates.[202] The Advisors assert that this recommendation would reduce ENO's

[200] *Id.*
[201] Ex. No. ADV-17 at 3:9-7:14.
[202] Ex. No. ADV-17 at 3:4-6.

revenue requirement related to its electric operations by $648,314 and the revenue requirement related to its gas operations by $145,211;[203] and

WHEREAS, ENO argues that this adjustment is unwarranted because the Advisors have not demonstrated that ENO's compensation plans are unreasonable.[204] However, the Advisors argue that incentive compensation plans and stock options may only be recovered in rates to the extent that the Company demonstrates that such plans benefit ratepayers.[205] Whether or not the Plan is reasonable, it is tied to the long-term performance of Entergy Corporation common stock, therefore the benefit of the Plan accrues solely to Entergy shareholders, and not to ratepayers, and therefore the costs thereof should not be recovered through rates.[206] The Advisors also point out that other jurisdictions have disallowed these costs from being recovered from customers for the same reasons that Advisors' witness Mr. Ferris cites in his testimony;[207] and

WHEREAS, the Council agrees with the Advisors that ENO has failed to provide support for its position regarding the inclusion of the Plan's costs in rates. Additionally, simply because a cost may be legitimate and prudent does not necessarily require those costs to be borne by ratepayers. The Council also notes that ENO incurs costs routinely that may be legitimate and prudent, but not recoverable from ratepayers. The Council further agrees with the Advisors that ENO has not provided any rational justification for recovering the costs of ENO's Restricted Stock Incentive Plan in rates. Accordingly, the Council finds that the Company has failed to meet its burden of showing that the Restricted Stock Incentive Plan benefits ratepayers and therefore, rejects ENO's proposal to include these costs in rates; and

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[203] Advisors' Initial Brief at 49, citing Ex. No. ADV-17 at 3:6-8.
[204] ENO Initial Brief at 163; Ex. No. ENO-3 at 50:14-17.
[205] Ex. No. ADV-18 at 4:5-7.
[206] *Id.* at 4:12-16.
[207] Ex. No. ADV-17 at 9:20-10:2 citing LPSC Order No. U-20925 (RRF 2004) and attached Recommendation on Contested Proposed Stipulated Settlement at 16.

ENO'S PREPAID PENSION ASSET ADJUSTMENT

WHEREAS, ENO included an adjustment for its Prepaid Pension Asset as part of its rate base;[208] and

WHEREAS, the Advisors argue that ENO's inclusion of the Prepaid Pension Asset in rate base is conceptually correct;[209] and

WHEREAS, the Advisors took exception to ENO's calculation of the asset included in rate base because it is based on a forecasted balance for the year-end December 31, 2018.[210] Instead of using forecasted calculations, the Advisors recommend that the Pension Asset balance be based on the actual December 31, 2018 balances[211] when provided by ENO, which would more accurately reflect the market value of the Asset;[212] and

WHEREAS, ENO argued that the Advisors' reasoning was incorrect because the Prepaid Pension Asset's growth is not driven by the market value of the pension trust fund assets but by ENO's contributions to the pension trust fund;[213] and

WHEREAS, upon receipt of ENO's responses to the Advisors' discovery requests regarding ENO's Prepaid Pension Asset adjustment, the Advisors found that ENO's actual funded status of its pension funds at December 31, 2018 was significantly less than the amount forecasted by Entergy's actuaries, AON Hewitt.[214] Also, ENO's actual balance for its benefit obligations regulatory asset at December 31, 2018 was significantly larger than the amount forecasted by AON

[208] ENO's Initial Brief at 150.
[209] Ex. ADV-9 at 63:9-10.
[210] *Id.* at 63:10-11.
[211] *Id.* at 63:11-14.
[212] The Advisors issued two discovery requests to ENO seeking information to determine the actual adjusted balance for the Pension Asset as of December 31, 2018. The two requests, CNO 12-2 and CNO 12-3 were outstanding at the time the Advisors were required to file direct testimony.
[213] ENO Initial Brief at 150.
[214] Ex. ADV-9 at 65:13-19.

Hewitt.[215] Further, AON Hewitt's overestimated funded status for ENO's pension funds and underestimated balance for ENO's benefit obligations regulatory asset at December 31, 2018, respectively, offset one another.[216] Therefore, the Advisors determined that as a result of this netting process, ENO's Pension Asset remains unaffected from differences between estimated and actual net gains and losses;[217] and

WHEREAS, in his Surrebuttal Testimony, Advisors' witness Mr. Proctor proposed that his recommendation for the Prepaid Pension Asset in rate base is also appropriate because it is supported by the lower historical five-year average year-end value of the Asset due to the growth of the Prepaid Pension Asset from recent financial market conditions and the amount of ENO's contributions;[218] and

WHEREAS, ENO responded that the Prepaid Pension Asset's growth is not driven by the market value of the pension trust fund assets but by ENO's contributions to the pension trust fund in excess of pension expense.[219] Contributions are tendered according to a plan provided by ENO's actuary setting forth the expected amount of the contributions and their timing.[220] Pension expense is generally determined at the beginning of the year by ENO's actuary.[221] ENO asserts that its discovery responses related to this issue show that the market value of the pension trust fund assets has no effect on the quantification of the Prepaid Pension Asset;[222] and

WHEREAS, the Council has considered the parties' positions related to ENO's Prepaid Pension Asset adjustment and concludes that the Asset should be included in rate base; and

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[215] *Id.*
[216] *Id.*
[217] Ex. ADV-9 at 66:14-16.
[218] *Id.* at 69:17-20.
[219] ENO Initial Brief at 151
[220] *Id.*
[221] *Id.*
[222] *Id.*

WHEREAS, the Council also believes that ENO has reasonably demonstrated that the market value of the pension trust fund assets does not have an effect on the quantification of the of the Prepaid Pension Asset for the purposes of inclusion of the Asset in base rates; and

WHEREAS, ENO's Prepaid Pension Asset adjustment should be included in rate base and quantified as proposed by the Company in its Revised Application; and

GAS INFRASTRUCTURE REPLACEMENT PROGRAM

WHEREAS, on January 26, 2017, in Docket No. UD-07-02, the Council adopted Resolution R-17-38 which authorized ENO "to proceed with the replacement of gas infrastructure . . . at a rate of approximately 25 miles per year and approximately $12.5 million in capital investment per year" until the resolution of the instant rate case docket;[223] and

WHEREAS, ENO proposes to establish a Gas Infrastructure Replacement Program ("GIRP") to recover its costs related the replacement of aging natural gas infrastructure to ensure the safety and reliability of its gas distribution system. Specifically, ENO proposes to include GIRP investment made through the end of this proceeding in the costs collected through the proposed GIRP Rider;[224] and

WHEREAS, ENO specifically proposes to replace or abandon a total of 238 miles of low-pressure cast iron and steel and vintage plastic pipes at an estimated cost of $119 million because, according to the ENO, cast iron and vintage plastic are two of the material types that the natural gas industry recognizes are prone to failure and recommends should be replaced.[225] ENO also argues that a gas distribution system that is entirely high-pressure also offers the benefit of

[223] Ex. No. ENO-22 at 16:19-17:2.
[224] *Id.*at 17.
[225] *Id.* at 15.

providing a form of "storm hardening," as high-pressure operation prevents the infiltration of water into the system;[226] and

WHEREAS, under the assumption that the rates implemented as a result of this rate case include plant in service through December 31, 2019,[227] ENO proposes to recover its GIRP investment and expenses that are placed into service and/or expended from January 1, 2020 through March 31, 2020 through the GIRP Rider;[228] and

WHEREAS, ENO's proposal contemplates that it will make a rate filing within 60 days of March 31, 2020 with new rates to become effective for bills rendered on and after the first billing cycle of July 2020.[229] The percent rate adjustment would be applied to each gas rate class (*i.e.*, Residential. Small General, Large General, Small Municipal, and Large Municipal) with the exception of the customers ENO describes as "Non-Jurisdictional."[230] Further, ENO is proposing quarterly rate redeterminations, with quarterly filings that would be submitted within sixty days after each subsequent three-month period; and

WHEREAS, the Company proposes that the term of the GIRP Rider will be in effect through 2027, regardless of whether an FRP remains in place for ENO.[231] If this GIRP Rider is terminated before 2027, then the Company proposes that the GIRP Rider Rate then in effect would remain in effect until the Council approves an alternative recovery mechanism;[232] and

WHEREAS, none of the Intervenors addressed the proposed GIRP Rider; and

[226] *Id.*
[227] *Id.*
[228] Ex. No. ENO-41 at 49.
[229] *Id.* at 49-50.
[230] Ex. No. ADV-6 at 80:4-7.
[231] *Id.* at 52.
[232] *Id.* at 52-53.

WHEREAS, Advisors' witness Watson testifies that ENO's proposed GIRP Rider is not necessary to allow ENO the opportunity to recover its related costs.[233] He states that "[t]hese GIRP-related costs are predictable and manageable by ENO." As such, other ratemaking mechanisms exist to allow ENO the opportunity to recover such costs such as ENO's proposed FRP.[234] Further, the Advisors note that "ENO witness Bourg testified, 'ENO agrees that a properly structured FRP would provide an appropriate means to adjust ENO's gas rates to allow it to recover its gas revenue requirements, including its GIRP-related costs and a reasonable return on its investment;'"[235] and

WHEREAS, Advisors' witness Rogers testifies that although he agrees that the proposed scope of GIRP is consistent with industry trends to identify risks and replace aging infrastructure prior to failure and will provide customers with a safer, more reliable gas distribution system, he expressed his concern regarding the resulting rate impact on ratepayers;[236] and

WHEREAS, the Advisors note that the costs related to GIRP investment through 2019 are estimated to have a bill impact on a typical 100 ccf/month residential customer of approximately $6.12/month with rates in the instant proceeding. The Advisors further note that the estimated costs related to GIRP investment <u>after</u> 2019 and the estimated costs related to address historical underground utility conflicts, the estimated bill impact on a typical 100 ccf/month residential customer peaks at approximately $20.45/month in 2026;[237] and

WHEREAS, the Advisors assert that ENO has not shown that the proposed scope and pace of the GIRP plan adequately mitigates its rate impact.[238] In this regard, the Advisors argue ENO

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[233] Ex. No. ADV-6 at 81:9-10.
[234] *Id.* at 81:11-14.
[235] *Id.* at 82:6-9, citing Rebuttal Testimony of Michelle P. Bourg at 8, (Docket No. UD-07-02) (Sept. 5, 2017).
[236] Ex. No. ADV-6 at 39-40:17-10.
[237] Ex. No. ADV-6 at 39:18-40.
[238] Advisors' Initial Brief at 90.

refrained from providing a specific estimate of the approximate number of miles of pipe that should be replaced annually to ensure the safety of the gas distribution system;[239] and

WHEREAS, ENO maintains its position for the original GIRP schedule presented in the Application;[240] and

WHEREAS, the Advisors make the following recommendations: (1) that the Council approve recovery of the GIRP infrastructure costs incurred as proformed through the end of 2019 as generally approved by Resolution No. R-17-38; (2) that the Council reject ENO's proposed GIRP Rider as it constitutes inappropriate single-issue ratemaking and any Council-authorized GIRP-related costs are more appropriately recovered in base rates as adjusted through the gas FRP evaluations; and (3) that ENO be required to identify potential measures to mitigate the identified impact on ratepayers; and

WHEREAS, the Advisors further recommend that given ENO's unwillingness to depart from its proposed pace of GIRP-related investments, the Council establish a that a working group composed of the Advisors, ENO, and Intervenors to explore appropriate cost mitigation measures;[241] and

WHEREAS, the Advisors have noted, and the Council is concerned that, ENO has changed the scope and cost budget for GIRP, including introducing a utility conflict survey cost in the instant proceeding and introducing abandonment of plant as a component of GIRP; and

WHEREAS, the Council believes that the safe operation of ENO's gas distribution system is the paramount concern but also remains concerned regarding the cost impact on ratepayers with respect to ENO's proposed gas infrastructure replacement program; and

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[239] *Id.*
[240] Ex. No. ENO-24 at 5:14-16.
[241] Ex. No. ADV-2 at 10:19-21.

WHEREAS, the Council agrees with the Advisors' recommendations and (1) finds that the GIRP infrastructure costs through the end of 2019 should be approved so as not to disrupt the gas infrastructure replacement; (2) rejects ENO's proposed GIRP Rider as it constitutes inappropriate single-issue ratemaking and finds that any Council-authorized GIRP-related costs are more appropriately recovered in base rates; and (3) requires ENO to identify potential measures to mitigate the cost impact of ENO's proposed GIRP plan; and

WHEREAS, in light of the considerable need to ensure that ENO's distribution gas pipeline operations are safe and reliable, the Council finds that ENO may continue to make prudent investments in gas distribution plant and incur prudent utility conflict survey costs as required to ensure the safe operation of ENO's gas utility, and that a working group should be established to consider all appropriate measures to mitigate harmful GIRP-related ratepayer impacts, as proposed by the Advisors; and

ALLOCATION OF CAPACITY COSTS ASSOCIATED WITH CERTAIN PURCHASE POWER AGREEMENTS

WHEREAS, in proposing customer class revenue requirements, ENO allocated capacity costs associated with the Resource Plan Purchase Power Agreements ("PPAs") using the relative percentage of energy sales (kWh) attributable to each rate class.[242] According to the Company, this allocation method decreases the capacity-related expenses allocated to the residential rate class and re-allocates those costs among the remaining customer classes.[243] According to ENO, the reallocation occurs as a matter of the Company's proposed rate design and is not reflected in ENO's electric cost of service study;[244] and

[242] ENO Initial Brief at 81.
[243] *Id.*
[244] *Id.*

WHEREAS, Advisors' witness Prep and CCPUG witness Baron object to the energy-based allocation of the Resource Plan PPAs capacity-related expenses; and

WHEREAS, specifically, for the allocation of capacity-related costs from Riverbend 30% PPA ("Riverbend 30") and Entergy Arkansas, Inc. Wholesale Base Load PPA ("EAI WBL"), Advisors' witness Prep used a production demand allocator, which is consistent with ENO's own electric cost of service study, rather than ENO's kWh/energy allocation of these fixed costs;[245] and

WHEREAS, CCPUG argues that ENO should allocate the capacity costs associated with the EAI WBL and River Bend 30% PPAs to each customer class on an equal percentage basis, just as it proposes to do with respect to the Ninemile 6 PPA and Algiers Transaction PPA capacity costs;[246] and

WHEREAS, CCPUG asserts that allocation of these costs on an equal percentage basis is a reasonable and well-accepted method to allocate and recover such fixed, non-fuel capacity costs, and ENO acknowledges that it is consistent with prior Council rate making decisions;[247] and

WHEREAS, CCPUG also points out that ENO proposes to treat the non-fuel, capacity costs related to the EAI WBL and River Bend 30% PPAs differently than it proposes to treat capacity costs associated with other PPAs, which are identical in nature;[248] and

WHEREAS, ENO argues, to the contrary, that the energy allocation not only is effective to address residential customer rate impacts, it is also founded on sound policy and cost causation principles;[249] and

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[245] Ex. No. ADV-3 at 28:2-4.
[246] CCPUG Initial Brief at 15-16.
[247] *Id.* at 15, citing Ex. No.. ENO-41 at 23:11-12. "[I]t has been the Council's practice to adjust base rates by applying an equal percentage change to all classes."
[248] *Id.* at 15.
[249] ENO Initial Brief at 82.

WHEREAS, the Council finds that CCPUG's concerns regarding the effect of ENO's proposed methodology to allocate these costs have merit; and

WHEREAS, the Council also concludes that Advisors' witness Prep's recommendation to require ENO to allocate these capacity costs on a production demand basis, as used in ENO's electric cost of service study, is more consistent with the Council's prior ratemaking decisions than ENO's proposal and also similar to ENO's treatment of other PPAs being realigned into base rates in this proceeding; and

WHEREAS, the Council disagrees with ENO's proposal to allocate capacity costs related to the EAI WBL and River Bend 30% PPAs to each customer class on a percentage of energy (kWh) sales; and

CCPUG'S PROPOSED RATE ADJUSTMENTS

WHEREAS, CCPUG made a number of recommended rate adjustments in this proceeding that the Council declines to adopt, including;

a. Remove Capital Storm Restoration Costs from Plant;
b. Remove Depreciation Expense Associated With Capital Storm Restoration Costs;
c. Remove Amortization of Algiers Migration Costs;
d. Reduce Depreciation Expense – Correct Patterson Solar Depreciation Rate;
e. Remove Reduction to ADIT for Excess ADIT Amortization in 2019;
f. Remove Algiers Migration Costs Net of ADIT;
g. Reduce Depreciation Expense – Use 0% Net Salvage for Union Power Block #1;
h. Extend Amortization of Algiers Transaction and Migration Costs to 10 Years; and

WHEREAS, the Council has carefully considered each of these recommended adjustments and finds that they should not be adopted for various reasons; and

WHEREAS, with respect to the adjustment, Remove Capital Storm Restoration Costs from Plant and Remove Depreciation Expense Associated With Capital Storm Restoration Costs, the Council is unpersuaded by CCPUG's proposals regarding the recovery of storm related costs and declines to alter the Council's longstanding practice of allowing the recovery of such costs; and

WHEREAS, with respect to the adjustment, Remove Amortization of Algiers Migration Costs, Remove Algiers Migration Costs Net of ADIT and Extend Amortization of Algiers Transaction and Migration Costs to 10 years, the Council declines to modify its previously approved Algiers transaction and migration cost amortization period; and

WHEREAS, as for CCPUG's proposed adjustment Reduce Depreciation Expense - Correct Paterson Solar Depreciation Rate, the Council is not persuaded that the Paterson Solar Project's depreciation rate as proposed by ENO is inappropriate since the project is reasonably viewed as a technology demonstration pilot project; and

WHEREAS, the Council also finds that the proposed adjustment, Remove Reduction to ADIT for Excess ADIT Amortization in 2019, would be inconsistent with the accepted ratemaking principle of allowing ENO the opportunity to recover its costs contemporaneously with their incurrence, including proforma costs that are known and measurable; and

WHEREAS, CCPUG's proposed adjustment, Reduce Depreciation expense – use 0% Net Salvage for Union Power Block #1, should not be adopted because the Council is not persuaded that Union Power Block #1's salvage will be 0%; and

WHEREAS, CCPUG did, however, make recommended rate adjustments that the Council believes should be adopted, including,

a. Correct Cash Working Capital to Include Dividend Component of Return on Equity;
b. Reduce Depreciation Expense – Use 40 Year Service Life for Union Power Block #1;
c. Extend Amortization Period for General Plant Reserve Deficiency from 10 Years to 20 Years;
d. Remove Forecast 2019 Increases in Payroll and Related Expenses; and

WHEREAS, with respect to the adjustment, Correct Cash Working Capital to Include Dividend Component of Return on Equity, the Council believes that this adjustment is reasonable and is consistent with the Council's overall goal of reducing base rates to the greatest extent practicable; and

WHEREAS, with respect to the adjustment, Reduce Depreciation Expense – Use 40 Year Service Life for Union Power Block #1, the Council adopts the position of CCPUG as discussed in greater detail herein; and

WHEREAS, with respect to CCPUG's adjustment, Extend Amortization Period for General Plant Reserve Deficiency from 10 Years to 20 Years, the Council believes that this adjustment is consistent with the Council's decision to use a 40 year service life for Union Power Block #1 which has the effect of reducing ENO's revenue requirement while maintaining ENO's opportunity to recover its prudently incurred costs; and

WHEREAS, with respect to the adjustment, Remove Forecast 2019 Increases in Payroll and Related Expenses, the Council finds that this adjustment should be adopted since ENO did not provide documentation or otherwise establish that these proforma expenses are known and measurable; and

WHEREAS, CCPUG made some recommended rate adjustments that were opposed by the Advisors in testimony and that the Council chooses not to adopt, including,

a. Remove Plant, A/D, and ADIT Proforma Adjustments Related to 2019 Additions;
b. Remove Depreciation Expense Related to 2019 Plant Additions; and

WHEREAS, the Council finds that these adjustments are inconsistent with the Council's decision in this resolution to generally allow ENO to include proforma costs that are known and measurable in rate base for the purpose of setting rates in this proceeding; and

COST ALLOCATION AND CUSTOMER CLASS REVENUE REQUIREMENTS

WHEREAS, ENO proposes several steps in the way that its total cost of service/revenue requirement is allocated among customers classes. These steps impact the extent to which various customer classes see a rate increase or decrease as a result of the overall revenue decrease proposed by ENO; and

(1) *Cost Allocation*

WHEREAS, ENO argues that its proposed cost allocation methodologies have been historically used by the Company and are consistent with those traditionally approved by the Council. The significant characteristic of ENO's cost allocation is the fact that ENO limits its cost of service allocations to only costs recovered in base rates.[250] ENO's allocations of all other costs in the total revenue requirement are effectively determined by ENO's proposed rider tariff design for revenue recovery. For example, ENO proposed an allocation of AMI costs (through its proposed AMI Rider) on the basis of numbers of customers (which heavily weights the AMI cost recovery on residential ratepayers);[251] and

WHEREAS, Air Products concurred with the cost allocation methodologies employed by ENO in the development of its electric class cost of service study, specifically the 12 coincident peak ("12 CP") method for the allocation of generation-related fixed costs and PPAs.[252] CCPUG Witness Baron stated that ENO's 12 Coincident Peak class cost of service study is a reasonable basis to evaluate the cost of service for each of the Company's rate classes;[253] and

WHEREAS, the Advisors generally accepted ENO's cost allocation methodologies with few exceptions. The Advisors differed with ENO with respect to the allocations of AMI costs.

[250] Ex. No. ENO-45 at 8: 14.
[251] Ex. No. ENO-41 at 6-7.
[252] Ex. No. AP-3 at 5.
[253] EX. No. CCPUG-5 at 14

Specifically, the Advisors recommend that the cost responsibility for AMI implementation should be based on the costs and benefits of AMI established in Docket No. UD-16-04;[254] and

(2) *Customer Class Revenue Requirements*

WHEREAS, ENO's class cost of service study shows the various customer class rates of return (limited to base rates rather than total costs of service) that result from present base rate revenues and the allocation of costs that ENO has identified as related to recovery with base rate revenues.[255] ENO's class cost of service study also shows how each customer class present base rate revenue differs from the customer class revenue that would provide a rate of return equal to that proposed by ENO[256]; and

WHEREAS, ENO's proposal for revenue changes by customer class does not follow its class cost of service allocation study filed in the Revised Application. Neither did ENO use its class cost of service study to show how its proposed revenue requirements by customer class changed the various customer class rates of return that correspond to present base rate revenues. Rather ENO proposed class revenue requirements based on an energy-based class allocation for its proposed cost allocation with regard to the capacity costs associated with Riverbend 30 ("RB30") and Entergy Arkansas, Inc. Wholesale Base Load ("EAI WBL") Purchased Power Agreements (PPAs"). ENO used the same approach to implementing the first step of its proposed Algiers Residential Rate Transition ("ARRT") plan. Next ENO applied a final class revenue adjustment pro-rated on present customer class base rate revenues;[257] and

WHEREAS, Air Products witness Brubaker proposed to adjust class revenues by first calculating the difference between the total revenues ENO requested and the total revenues

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[254] Ex. No. ADV-3 at 28: line 4.
[255] Revised Application, at MFR, COS, Period II, Section FF, Statement RR-1.
[256] *Id.*
[257] Revised Application at 26-30.

awarded by the Council, and then spreading that difference to only those customer classes whose revenues would be above cost of service under ENO's rate proposal.[258] Alternatively, CCPUG's witness Baron regarded the important issue in this case to be the extent to which the Council follows the cost of service results in its revenue allocation decision.[259] However, he then recommended that base rate revenues be increased by a uniform percentage amount,[260] with a cap on the total revenue change at a 2% increase level. CCPUG also proposed that the first $3.325 million of Council approved revenue adjustments should be applied to eliminate the increases proposed for the four Large Industrial classes proposed by ENO to fund ENO's proposed Algiers residential mitigation plan;[261] and

WHEREAS, the Advisors' recommendation is to develop proposed customer class revenue requirements using ENO's class cost of service analysis to evaluate how each change to customer class revenue relates to changes in the customer class rates of return. The Advisors contend that the Council should be provided such specific information on the relative rates of return among the customer classes in its determination of the appropriate changes to the revenue responsibility of each customer class;[262] and

WHEREAS, as proposed by the Advisors, the cost of providing service is related to the established total revenue for each customer class. When class allocations are finalized for all other components of the cost of service except return, the class cost of service model provides the specific information related to discrete changes in present class revenues and rates of return. The Advisors used this information to make recommendations to the Council regarding individual

[258] Ex. No. AP-3 at 15: 10.
[259] Ex. No. CCPUG-5 at 13-15.
[260] Ex. No. CCPUG-5 at 25.
[261] Ex. No. CCPUG-5 at 26, Table 6.
[262] Ex. No. ADV-3 at 30-32.

customer class revenue requirements while recognizing the disparity among the customer class rates of return and the impacts of changes to each customer class total present revenue.[263] Thus, based on the Council approved revenue requirement (cost of service) level for each customer class in this case, the resulting rates of return for each customer class would then be used in the subsequent FRP to calculate the return component of the FRP customer class revenue requirement and the decoupling revenue adjustment.[264] Any adjustments to the customer class relative rates of return should be movements towards the total utility rate of return; and

WHEREAS, the Council finds that the Advisors' approach to setting customer class revenue requirements as indicated in Exhibits VP-20 and VP-21 is a preferred cost-based approach and provides the Council with information relating revenue changes to impacts on customer class rates of return; and

REALIGNMENT OF RATE STRUCTURE

WHEREAS, ENO proposes to eliminate two obsolete customer classes (Master Metered Residential and Experimental Interruptible) and to consolidate its Small Electric Service and Traffic Signal Service classes into a single class. ENO also proposes to consolidate all of its private area lighting services into a single customer class. ENO Witness Talkington addressed the proposed combination of Algiers non-residential rates with Legacy ENO rate classes. As a result, the Company's electric cost of service studies are based on allocating costs to nine customer rate classes. ENO proposes to discontinue all existing Algiers rate schedules, except for the Market Valued Load Modifying Rider ("MVLMR") and Market Valued Demand Response Rider

[263] Ex. No. ADV-5 at 15.
[264] *Id.*

("MVDRR"), which ENO proposes to available all ENO customers and qualified demand response aggregators of retail customers;[265] and.

WHEREAS, none of the Intervenors contested ENO's realignment of rate classes and rate structures; and

WHEREAS, the Advisors do not oppose ENO's proposal to eliminate and consolidate customer classes, including the existing Algiers electric tariffs, to be combined into nine electric customer rate classes;[266] and

WHEREAS, in light of the agreement of ENO and the Advisors regarding the elimination of the relevant obsolete customer classes and the consolidation, including the existing Algiers electric tariffs, into nine electric customer rate classes and the lack of opposition from any other party, the Council approves the proposed rate realignments; and

NON-JURISDICTIONAL GAS CUSTOMERS

WHEREAS, Non-Jurisdictional ("NJ") customers are a subset of industrial customers for whom ENO provides interruptible gas service pursuant to negotiated special non-published contracts.[267] Advisor witness Prep notes that these customers were not included in ENO gas cost of service study and as such there is no basis under that approach to determine their allocated cost responsibility;[268] and

WHEREAS, ENO did not address this class of gas customers in its Revised Application or Direct Testimony. In response to the Advisors' testimony, ENO takes issues with the Advisors' recommendation that NJ customer rates should be reviewed and that, according to ENO, placing the existing NJ customers on the Large General Service rate would not be in the customer's best

[265] Ex. No. ENO-45 at 33.
[266] EX. No. ADV-4 at 64-65.
[267] Ex. No. ENO-25 at 27.
[268] Ex. No. ADV-3 at 50.

interest because it would likely result in a material increase in the cost for gas service for this class of customers. ENO argues that "[b]y offering interruptible service under special contracts to these customers, gas service should be able to remain competitive with the prices available to other similar industrial customers with whom the ENO industrial customers are in competition."[269] ENO also notes that by continuing to serve NJ customers under special contracts also means that theses interruptible gas customers will be served in a manner similar to the way gas service is provided to all other industrial customers throughout the state because the natural gas prices paid by customers classified as industrial are a confidential matter between the customers and the seller;[270] and

WHEREAS, none of the Intervenors addressed NJ gas customers' rates; and

WHEREAS, the Advisors assert that ENO's use of "NJ" to refer to these customers is a misnomer because the rates or charges applied to any person or entity receiving gas or electric service in New Orleans are subject to Council retail rate regulation. Since NJ customers receive gas service through the same gas distribution system mains as do all other ENO gas customers and all NJ customers are located in New Orleans, the Advisors contend that NJ customers are subject to Council retail rate regulation;[271] and

WHEREAS, although there is no NJ customer cost analysis, the Advisors argue that NJ customers' rates and established business operations in New Orleans should not be modified without careful Council evaluation. Instead, the Advisors recommend: (1) that ENO should be required to provide a complete cost of service analysis in support of the NJ customers' rates as part of future Council rate actions; (2) that the Council affirm that the terms under which ENO

[269] Ex. No. ENO-25 at 30.
[270] *Id.*
[271] *Id.* at 52.

offers gas service to the NJ customers are subject to Council retail rate regulation; (3) that the Council direct ENO not to execute any new NJ contracts without express Council approval;[272] and

WHEREAS, the Council agrees that NJ customers are subject to the Council's rate regulation authority and the Council finds that the Advisors' argument that the Council in the exercise of that authority should carefully evaluate whether NJ rates are just and reasonable and in the public interest. Thus, we direct ENO to provide a complete cost of service analysis in support of the NJ customers' rates as part of ENO's 2020 gas FRP filing; and

NEW RIDERS FOR COST RECOVERY

WHEREAS, ENO is proposing several new or revised riders, each of which would allow ENO contemporaneous and nearly exact recovery of its related cost. The riders include:

- Fuel Adjustment Clause rider ("FAC Rider"): recovery of fuel and energy costs, including the recovery of certain power purchase agreement ("PPA") related capacity costs;[273]
- Purchase Gas Adjustment Clause Rider ("PGA Rider"): recovery of costs related to the provision of gas sold to ENO's retail customers;[274]
- Midcontinent Independent System Operator, Inc. Rider ("MISO Rider"): recovery of costs charged to ENO pursuant to the MISO Open Access Transmission Energy and Operating Markets Tariffs that are not recovered via the Fuel Adjustment Clause;[275]

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[272] *Id.* at 55-56.
[273] Revised Application at 30
[274] *Id.* at 31.
[275] *Id.*

- Purchase Power and Capacity Acquisition Cost Recovery Rider ("PPCACR"): recovery of certain PPA-related capacity costs, Long-Term Service Agreement ("LTSA") costs, and the non-fuel revenue requirement related to future constructed and/or acquired capacity additions;[276]
- Distribution Grid Modernization Rider ("DGM Rider"): recovery of costs related to certain distribution investments and O&M expenses characterized by ENO as relating to grid modernization;[277]
- Interim Energy Efficiency Cost Recovery Rider ("EECR Rider"): recovery of costs related to the Council's Energy Smart program over an interim period;[278]
- Demand-Side Management Cost Recovery Rider ("DSMCR Rider"): recovery of costs related to the Council's Energy Smart program upon the expiration of Interim EECR Rider;[279]
- Gas Infrastructure Replacement Program Rider ("GIRP Rider"): recovery of costs related to gas distribution investment beyond 2019 and recovery of utility conflict survey costs;[280]
- Advanced Metering Infrastructure ("AMI") Charge for Electric Service ("AMICE Rider")/Advanced Metering Infrastructure Charge for Gas Service ("AMICG Rider"): recovery of net costs

[276] *Id.* at 32
[277] *Id.* at 34-36.
[278] *Id.* at 34.
[279] *Id.* at 33-34.
[280] *Id.* at 36.

related to AMI deployment beyond 2019 for electric and gas respectively;[281] and

WHEREAS, in support of these riders, ENO argues that utilities are currently undergoing a paradigm shift caused by the need for large new capital additions at a time of increasing costs and decreasing average usage per residential customer and that a regulatory environment that provides for contemporaneous cost recovery of large investments outside of the traditional rate case provides the utility the necessary opportunity to earn its allowed return while continuing to invest in the system and mitigate operational risks;[282] and

WHEREAS, in contrast, the Advisors urge caution in using riders as cost recovery mechanisms. To eliminate single-issue ratemaking, the Advisors recommend that the Council deny ENO's request for Council approval of certain riders that would provide exact cost recovery for their respective costs, *i.e.*, a near-guarantee that ENO will recover all of its costs contemporaneous with their incurrence or through a true-up mechanism involving carrying costs for any under collection balance; and

WHEREAS, the Advisors note that historically, riders were only approved by regulators in rare instances to address volatile and uncontrollable costs, such as the recovery of fuel and purchased power costs or natural gas commodity costs through a fuel adjustment rider or purchased gas adjustment rider. Advisor witness Rogers testifies that typically, riders are used for costs that can be significantly variable in nature and outside the control of utility. This is the case with respect to ENO's FAC, PGA, and MISO riders. At other times, riders may be used to provide for the recovery of significant costs incurred between full rate case proceedings that were not otherwise accounted for in base rates; and

281 *Id.* at 37-38.
282 Ex. No. ENO-2 at 53.

SINGLE-ISSUE RATEMAKING

WHEREAS, the Advisors raise significant concerns regarding ENO's request for Council approval of riders that would provide exact cost recovery for their respective costs (*i.e.*, a near-guarantee that ENO will recover all of its costs contemporaneous with their incurrence or through a true-up mechanism involving carrying costs for any under collection balance). Specifically, the Advisors recommend that such riders should be rejected when they constitute inappropriate single-issue ratemaking. Advisor Witness Watson testifies that single-issue ratemaking is a deviation from the accepted regulatory ratemaking principle that rates should generally be based on a utility's overall costs and risks.[283] The Supreme Court of Louisiana has found that "[s]ingle issue ratemaking occurs when a utility's rates are altered on the basis of only one of the numerous factors that are considered when determining the revenue requirements of a regulated utility."[284] Said differently, single-issue ratemaking occurs when particular portions of a utility's revenue requirement are considered for recovery in isolation from the utility's total costs and revenues;[285] and

WHEREAS, the Advisors also note that "[s]ingle-issue ratemaking is generally not appropriate because its application is contrary to the generally accepted regulatory ratemaking principle that a utility's rates that produce its revenues should be based on a utility's overall costs. Single-issue ratemaking may not capture the overall impact of the portion of a utility's revenue requirement under special consideration by potentially not reflecting offsetting changes in other areas of the utility's operations;[286] and

[283] Ex. No. ADV-3 at 73-77.
[284] *Id.* at 75-76.
[285] *Id.* at 74.
[286] *Id.* at 75.

WHEREAS, single-issue ratemaking may have the adverse impact of reducing a utility's incentive to control its costs to the extent such ratemaking guarantees cost recovery through a true-up mechanism. As such, single-issue ratemaking is particularly inappropriate when other ratemaking mechanisms that are not subject to single-issue ratemaking deleterious effects are available, such as recovery of the same costs through base rates;[287] and

WHEREAS, it should be noted that the Advisors do not recommend an across-the-board prohibition on riders as recovery mechanisms, acknowledging that there may be valid and supportable reasons to use a rider to recover certain costs of service. The Advisors note that a rider may be acceptable if the specific costs are substantial, vary significantly and/or are unpredictable, or require periodic review by the Council. In those instances, the Advisors recommend that an appropriately selected Rider should generate revenue from each customer class based on the costs determined to be recovered from each customer class as reflected in the allocation of the total cost of service;[288] and

WHEREAS, the Advisors also note that a utility is entitled only to the opportunity to earn a reasonable return on its investment, and that the law does not insure that a utility will in fact earn the particular rate of return authorized by a Commission or even that it will earn any net revenues. ENO should be allowed a reasonable opportunity to recover its prudently incurred costs and earn a reasonable return on its investments. The reasonable return on investment is primarily influenced by the Council setting a ROE at a level that is comparable to that being earned by other companies with comparable risks, maintains ENO's financial integrity, and maintains ENO's ability to raise capital;[289] and

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[287] *Id.*
[288] *Id.* at 76-77.
[289] *Id.* at 77.

WHEREAS, in response to ENO's argument that its proposed rider address the risk of undue regulatory lag, the Advisors note that if their recommendation for an annual electric and gas FRPs for a period of three years is approved the FRPs will help to mitigate ENO's concerns related to regulatory lag because the FRP would provide for an annual adjustment to ENO electric and gas rates to reduce the time between regulatory base rate actions. Additionally, to further mitigate regulatory lag, the Advisors recommend that ENO be allowed to include prospective proforma adjustments for known and measurable capital additions budgeted for the 12-month period immediately following the FRP test year. Thus, ENO's **known and measurable** costs that will occur in the rate effective period will be reviewed and considered for recovery in the annual FRP process; and

GRID MODERNIZATION

WHEREAS, ENO contends that its grid modernization investments differ from grid maintenance investments in that the latter costs are typically incurred as part of a utility's ordinary course of business and are required for a utility to continue to provide reliable service in the short term.[290] According to ENO, grid maintenance investments are typically reactive in nature and are incurred due to problems presented by existing equipment (*e.g.*, replacing damaged or aging assets, addressing compliance issues, etc.). In contrast, grid modernization investments are proactive investments designed to enhance the functionalities and services that grid infrastructure can provide to customers, while also changing the paradigm for evaluating and maintaining the reliability of the distribution system; and[291]

WHEREAS, ENO also notes that the five current grid modernization projects that were discussed in ENO's Revised Application and testimony are expected to improve reliability by

[290] Ex. No. ENO-6 at 34:13-35:5.
[291] *Id.*

reducing the number of customer interruptions by more than 53,000 per year and lowering the number of customer minutes of experienced interruptions by approximately 7.2 million per year.[292] The costs for these projects are estimated at $59.3 million[293] through January 31, 2022, of this amount $12.8 million is funded through ratepayer savings due to the effects of the TCJA.[294] Prudently-incurred costs related to the remaining $46.5 million, would be appropriately recoverable through rates. Additionally, ENO proposes that the investment associated with the portions of the grid modernization projects expected to close to plant in service by December 31, 2019, be reflected in base rates adopted in this proceeding;[295] and

WHEREAS, with regard to portions of the above projects closing after December 31, 2019, and any future grid modernization projects, ENO is proposing that the Council, in this proceeding, approve Rider DGM as the cost recovery mechanism. As proposed, Rider DGM would consist of a charge based on a percentage of base rates that is incremental to base rates and would recover depreciation and return on grid modernization investments made in the applicable year. The rider would be updated on a quarterly basis to include any new investments made in the preceding three months for the grid modernization projects described above, or for future grid modernization projects;[296] and

WHEREAS, AAE and CCPUG oppose the proposed DGM rider. According to AAE, ENO did not provide any justification for this choice of rate structure.[297] Further, AAE asserts that the DGM rider "effectively increases the fixed customer charge, and therefore reduces consumer incentives for energy conservation."[298] AAE also argues that ENO's grid modernization

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[292] Ex. No. ENO-8 at 24:5-7.
[293] Ex. No. AAE-3 at 35:7-8.
[294] Tax Cuts and Jobs Act of 2017, Pub, L. 115-97, 131 Stat. 2054, December 22, 2017.
[295] Ex. No. ENO-41 at 54:1-2.
[296] Ex. No AAE-3 at 35.
[297] Ex. No. AAE-3 at 36:4-13.
[298] *Id.*

investments are investments in the shared distribution system and do not encompass any customer-related functions or involve costs that otherwise vary directly with the number of customers on the system or connecting a customer to the system.[299] Thus, AAE states that the charge is unreasonable both from a perspective of public policy in support of energy efficiency, and from the perspective of cost causation;[300] and

WHEREAS, AAE's also contends that the charges to be recovered in Rider DGM should be aligned with how the Company charges for distribution service more generally, i.e., recovery through base rates. Noting that the current five projects target reliability improvements rather than demand growth, the charge associated with these investments should also be volumetric for non-residential customers;[301] and

WHEREAS, CCPUG argues that "[i]f the EFRP and GFRP are adopted, they likely will result in annual rate increases starting in 2020. If the DGM Rider and/or GIRP Rider are adopted, they will result in quarterly rate increases starting in 2020. These rider increases will be above and beyond any rate increases resulting from the electric and gas FRPs or any future base rate proceeding unless and until these riders are terminated";[302] and

WHEREAS, the Advisors contend that the proposed DGM Rider would allow ENO quarterly rate adjustments to recover expected costs related to grid modernization investments and provides for an annual true-up of rider collections versus actual revenue requirements. As such, the DGM Rider constitutes guaranteed exact cost recovery of certain distribution investments that ENO has classified as grid modernization.[303] Moreover, the Advisor emphasize that these costs

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[299] *Id.*
[300] *Id.*
[301] *Id.* at 36-37.
[302] Ex. No. CCPUG-1 at 4:15-19.
[303] Ex. No. ADV-7 at 88:9-11 (HSPM).

are predictable and within ENO's control, thus lacking the cost attributes (unpredictable and volatile) that generally require recovery through a Rider;[304] and

WHEREAS, the Council agrees with the Intervenors and the Advisors that ENO's DGM Rider is unnecessary. As the Advisors correctly note that the DGM Rider constitutes inappropriate single-issue ratemaking because it sets a separate rate recovery mechanism for ENO's incremental distribution investments.[305] Further, the DGM rider is not necessary to allow ENO the opportunity to recover its prudently-incurred costs, as other ratemaking mechanisms, i.e., base rates and FRP, are available to allow ENO recovery of its grid modernization-related costs;[306] and

ALGIERS RESIDENTIAL MITIGATION PLAN

WHEREAS, the Advisors note that one goal of the Council to be implemented in this rate proceeding is to address the disparity between the revenues provided by the present rate tariffs for Algiers residential customers and Legacy ENO residential customers.[307] According to ENO's Revised Application, the typical Algiers residential monthly bill (1,000 kWh/mo.) is $104.28 as opposed to $122.11 for customers on the East Bank.[308] The Council, in Resolution No. R-17-504, directed ENO to present one combined cost of service study and one combined set of rate schedules for the Legacy ENO and Algiers customers, "*unless significant rate shock could occur to single or multiple classes of customer[s]*;"[309] and

WHEREAS, under the Company's proposed combined residential rate without any rate mitigation, according to ENO's Revised Application a typical residential Algiers monthly bill

[304] *Id.* at 89:6-7 (HSPM).
[305] *Id.* at 86:20-21 (HSPM).
[306] *Id.* at 89:15-17 (HSPM).
[307] Advisors Initial Brief at 54.
[308] Ex. No. ENO-55, Statement A-5; Advisors' Initial Brief at 54.
[309] Ex. No. ENO-55 at 27, quoting Resolution No. R-17-504.

would see a $16.16 increase or 15.50%,[310] which the Advisors consider a wholly unacceptable impact.[311] In order to reduce the rate shock for Algiers residential customers that would otherwise result from a strict adherence to ENO's proposed residential revenue requirement and a combined residential rate, ENO proposed to phase-in the revenue increase to Algiers residential customers so that an Algiers residential customer's typical bill increases no more than 3.5% per year;[312] and

WHEREAS, as proposed by ENO, the first step of the phase-in will be implemented as a part of the rates ultimately approved by the Council in this case and Algiers bills would increase by 3.5%, or approximately $3.65 on a typical residential bill.[313] The second step of the phase-in would be in September 2021, at the same time as the annual revenue adjustments that would be authorized under its proposed FRP.[314] ENO notes that the second step in 2021 foregoes an additional ARRT-related increase for Algiers customers in 2020, when the NOPS is tentatively scheduled to be included in ENO's rates.[315] As proposed, Algiers residential bills will increase in 2021 by another 3.5%, or $3.76 on a typical residential monthly bill, moving them closer to parity with other Legacy ENO residential customers;[316] and

WHEREAS, in order to implement the ARRT plan proposed by ENO, the costs that Algiers residential customers would otherwise pay under the combined rate are paid for by four other participating rate classes - Large Electric, Large Electric High Load Factor, High Voltage, and Large Interruptible rate classes, classes that would otherwise receive an overall bill reduction of 10% or more as a result of the proposed rates.[317] These industrial rate classes would see an

[310] Ex. No. ENO-2 at 14:14-18.
[311] Ex. No. ENO-45, at Exhibit MLT-3; Advisors' Initial Brief at 54.
[312] Ex. No. ENO-45 at 30:8-17.
[313] *Id.* at 30:8-11, Exhibit MLT-3; ENO Initial Brief at 88.
[314] ENO-45 at 30:21-31:1.
[315] Ex. No. ENO-55 at 28.
[316] Ex. No. ENO-45 at 30:13-17, Exhibit MLT-3; ENO Initial Brief at 88.
[317] ENO Initial Brief at 88-89.

offsetting rate reduction in September 2021 when the second step increase is implemented for Algiers residential customers;[318] and

WHEREAS, ENO proposes a Base Rate Adjustment Rider to implement the ARRT plan. The rider contemplates two step changes in the rates of the Algiers residential customer and other four participating classes;[319] and

WHEREAS, Air Products, BSI and AAE do not address ENO's proposed ARRT plan; and

WHEREAS, CCPUG does not oppose ENO's ARRT Plan but argues that it should be modified such that the first $3.325 million of any reduction in ENO's proposed base rate revenue requirement increase are designated for the Large Electric, Large Electric High Load Factor, High Voltage, and Large Interruptible rate classes that would bear the funding for ENO's ARRT proposal;[320] and

WHEREAS, the Advisors propose a residential combined rate adjustment for Algiers, which would be a revenue adjustment between Legacy ENO residential customers and Algiers residential customers and would be applied with each prospective annual rate action until parity was reached.[321] Instead of ENO's proposed 3.5% increase to Algiers residential customers, the Advisors propose that Algiers' residential customers would have no initial revenue change in the instant docket.[322] The Advisors propose that subsequent to the instant proceeding and under a combined residential rate, the adjustment could increase Algiers residential revenue 4%, with a corresponding adjustment to Legacy ENO customers such that the combined adjustment would reflect the revenue change for the total residential class.[323] If the total residential revenue increase

[318] ENO Initial Brief at 88.
[319] Ex. No. ENO-45 at 31:14-20.
[320] CCPUG Initial Brief at 19.
[321] Advisors Initial Brief at 57.
[322] *Id.*
[323] *Id.*

was less than 4%, Algiers residential revenue would be increased 4% in subsequent rate actions and the increase to Legacy ENO residential would be moderated accordingly to reflect the total residential class increase. If a prospective ENO-wide residential revenue increase was greater than 4%, all residential customers, including Algiers, would receive the revenue change exceeding 4%;[324] and

WHEREAS, the Advisors explain that their Algiers proposal could be implemented in the context of a Rider applicable to the combined residential base rate tariff and would extend to future rate actions as necessary;[325] and

WHEREAS, the Advisors note that the CCPUG proposal would, in effect, transfer the funding of Algiers mitigation to all other customers except those four large industrial customer classes.[326] CCPUG argues, however, that it would simply eliminate the subsidy;[327] and

WHEREAS, ENO proposes to achieve the Algiers mitigation through implementation of a rider, while the Advisors propose a base rate tariff alternative.[328] ENO opposes implementing Algiers residential customer mitigation through changes to the existing residential base rate tariff arguing that it would add significant unnecessary complexity to the tariff design and billing of residential customers with the potential for unnecessary customer confusion.[329] ENO also opposes the alternative of making future AART rate changes in the context of the FRP, arguing that implementing the change through the larger context of the FRP dilutes the extent to which the annual adjustments address the disparity between residential customers and does not assure that the disparity will be eliminated in a reasonable time frame;[330] and

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[324] *Id.*
[325] *Id.* at 58.
[326] *Id.* at 56.
[327] CCPUG Reply Brief at 28.
[328] ENO Initial Brief at 91.
[329] *Id.*
[330] *Id.* at 92.

WHEREAS, ENO also opposes CCPUG's proposal that the first $3.325 million of any Council-approved revenue adjustment to ENO's requested revenue requirements be used to eliminate ENO's proposed Base Rate Adjustment Rider changes to large customers.[331] ENO argues that this proposal improperly intermingles the establishment of the overall revenue requirement with the class allocation of that revenue requirement;[332] and

WHEREAS, the Council agrees with ENO and the Advisors that under the new combined residential rate, it is necessary to mitigate the revenue related to Algiers residential customers. The Council agrees with the Advisors that since the majority of customers will receive a general rate reduction from the instant proceedings, the Algiers mitigation plan should have no change for Algiers residential revenue; and

WHEREAS, all parties appear to support rate mitigation for Algiers residential customers. The most significant difference between ENO's mitigation proposal and the Advisors' mitigation proposal is that ENO's approach would reallocate revenues from the Algiers residential class to the classes that would otherwise receive the largest rate decreases of any of the customer classes, while the Advisors' approach would reallocate revenues from the Algiers residential customers to the Legacy ENO residential customers which would reduce the amount of rate decrease they would otherwise receive in the instant docket under the combined rate; and

WHEREAS, while the Council appreciates that general ratemaking principles would suggest keeping all residential costs and revenues within the residential class, in light of the specific facts of this case, the Council finds that it serves the public interest better to reallocate the revenues to the classes that would otherwise receive the largest rate decrease. The Council finds that the Algiers mitigation will be funded from the Large Electric, Large Electric High Load

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[331] *Id.* at 93; ENO Reply Brief at 54.
[332] *Id.;* ENO Reply Brief at 54.

Factor, High Voltage, and Large Interruptible rate classes in proportion to their base rate revenue requirements; and

WHEREAS, the other primary difference between ENO's proposal and the Advisors' proposal is the timing and size of the increases to Algiers' rates. The Council finds that, consistent with the Advisors' recommendations, there will be no revenue change for Algiers residential customers in the initial rates set in this proceeding. Starting in 2021 with rates effective with that year's FRP evaluation, Algiers residential revenue will increase by a minimum of 4%, or equal to the residential class revenue increase when greater than 4%, until parity is achieved with the remainder of the residential rate class; and

WHEREAS, the Council agrees with the Advisors that the adjustment should be tied to the E-FRP. The Council finds that significant rate increases related to the E-FRP, if added to a 4% rate increase due to the Algiers residential mitigation plan could result in an unreasonable rate increase in a particular year; and

WHEREAS, the Council finds that subsequent to the final order designating the residential class revenue requirement, ENO should develop the combined residential rate tariff that provides the designated revenue impact to Legacy ENO residential as well as the revenue mitigation required to maintain Algiers residential revenue at present levels without an increase. The Council also finds that a specific rider tariff should be used to identify the amount of Algiers residential mitigation revenue required from each of the identified four rate classes based on the fixed cost portion of their customer class revenue requirements as designated in the final Order of this proceeding; and

ADJUSTMENTS TO FUEL ADJUSTMENT CLAUSE ("FAC") RIDER

WHEREAS, ENO proposes several changes to its FAC Rider. The first is to combine the separate FAC riders for Legacy ENO customers and Algiers customers into a single FAC Rider for all customers.[333] ENO also proposes: (1) to modify the recovery of the Resource Plan PPA capacity expenses to include recovery of the difference between estimated monthly capacity expenses and that amount recovered through base rates and, and the actual monthly capacity expenses; (2) elimination of the recovery of LTSA expenses, which ENO proposes to recover through base rates and the PPCACR Rider; (3) elimination of the Grand Gulf repricing mechanism for Algiers Customers, (4) elimination of the allocation to Legacy ENO customers of Union Power Block #1 fuel costs and wholesale revenues so that all customers are allocated these expenses and benefit from these revenues; (5) combination of the two over/under balances into a single over/under balance; and (6) use of per book rider revenue instead of calculated FAC collections;[334] and

WHEREAS, the Advisors state that the proposed combined FAC Rider is significantly simpler than the rider it is intended to replace and produces a single FAC Rider rate for both Legacy ENO Customers and Algiers Customers by eliminating the Geographic-Specific adjustments.[335] The Advisors believe this represents a significant improvement with respect to ease of calculation and understanding.[336] The Advisors did, however, note some errors in the formulas and references and also an inconsistency in the formulas in ENO's Exhibit No. SMC-2 for the treatment of certain

[333] Ex. No. ENO-55 at 30.
[334] *Id.* at 31; *see also*, Ex. No. ENO-44 at 5:1-6:12.
[335] Advisors' Initial Brief at 95, citing Ex. No. ADV-1 at 23:7-9.
[336] *Id.*, citing Ex. No. ADV-1 at 23:9-10.

costs as compared to historical treatment and the treatment proposed in ENO's proposed PPCACR Rider for similar costs;[337] and

WHEREAS, ENO submitted no testimony in response to the errors noted by the Advisors, rather, ENO stated that there are no substantive disputes regarding the FAC Rider Schedule.[338] ENO stated that the only outstanding issue concerns which over and under collections, if any, should be included in the rider, which is dependent on the final resolution of allocation issues.[339] ENO proposes that this component of the rider be addressed in the compliance filing process.[340] The Advisors support this suggestion, and therefore recommend that the Council approve the proposed FAC Rider Schedule, as corrected by the Advisors;[341] and

WHEREAS, ENO supports the Advisors' corrections to the FAC Rider;[342] and

WHEREAS, in light of the agreement of ENO and the Advisors as to the corrections and the lack of opposition from any other party, the Council approves the proposed FAC Rider as corrected by the Advisors; and

PURCHASED GAS ADJUSTMENT RIDER

WHEREAS, ENO proposes to use per book PGA Rider revenue instead of calculated PGA Rider collections in order to ensure a more accurate calculation by reflecting customer billing corrections recorded in the operations month;[343] and

WHEREAS, the Advisors note that the proposed combined PGA Rider is similar to the rider it is intended to replace.[344] The Advisors explain that ENO has proposed modifications from

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337 Advisors' Initial Brief at 95, citing Ex. No. ADV-1 at 23:11-27:8.
338 Ex. No. ENO-3 at 6:5-7; *see also*, ENO Post-Hearing Brief at 178.
339 Ex. No. ENO-3 at 6:7-9; *see also*, ENO Post-Hearing Brief at 178-179.
340 Ex. No. ENO-3 at 6:9-10.
341 Advisors' Initial Brief at 96.
342 ENO Reply Brief at 118-119.
343 Advisors' Initial Brief at 96, citing Ex. No. ENO-55 at 31.
344 *Id.*, citing Ex. No. ADV-1 at 28:1.

the previous rider to revise the formulas for calculating the over/under balance to utilize per book PGA Rider revenue.[345] A similar treatment is included in ENO's proposed FAC Rider, and the change in the source data for the calculation will not make a material difference in the rate charged under the FAC Rider or PGA Rider.[346] The Advisors did note some errors in the formulas of the proposed PGA Rider and recommend the Council approve the Rider as corrected for these errors;[347] and

WHEREAS, ENO recommends that the Council approve the proposed PGA Rider subject to the correction of the errors identified in Advisors' Exhibit No. JWR-5;[348] and

WHEREAS, in light of the agreement of ENO and the Advisors as to the corrections and the lack of opposition from any other party, the Council approves the proposed PGA Rider as corrected by the Advisors; and

PPCACR

WHEREAS, ENO explains that, effective with new base rates from this proceeding, it will no longer recover the UPS and Ninemile 6 PPA costs exclusively through the Rider PPCACR.[349] ENO proposes to transfer current Rider PPCACR costs relating to the UPS acquisition and the Ninemile 6 PPA into base rates in this proceeding, and then reset the PPCACR Rider at zero.[350] On a going-forward basis, ENO then proposes to include three types of recoverable costs in revised Rider PPCACR: (1) the incremental difference between the estimated, approved PPA and LTSA costs in the new base rates and the actual PPA and LTSA costs incurred on a monthly basis; (2) costs related to newly constructed and/or acquired capacity; and (3) costs related to new PPAs the

[345] *Id.*, citing Ex. No. ADV-1 at 28:1-3.
[346] *Id.*, citing Ex. No. ADV-1 at 5-7.
[347] *Id.*, citing Ex. No. ADV-1 at 28:8-29:6.
[348] ENO Post-Hearing Brief at 179; *see also* ENO Reply Brief at 119.
[349] Advisors' Initial Brief at 96.
[350] *Id.* at 96-97.

Company may enter into as approved by the Council.[351] ENO proposes to allocate the Rider PPCACR revenue requirement to the rate classes using the base rate revenue requirement allocation methodology approved by the Council in this proceeding.[352] Similar to the current PPCACR Rider, ENO proposes a cumulative over/under calculation that compares the cumulative over/under balance and the applicable monthly costs to the PPCACR Rider Revenue for that operations month.[353] Any prior period adjustments will be added or subtracted and an interest component will be applied based on the average of the beginning of the month and end of the month cumulative over/under balance for the operations month using that month's prime interest rate;[354] and

WHEREAS, Air Products supports the PPCACR Rider to allocate cost recovery as an equal percent of base rate revenue as reasonable in the absence of the utility to use a more specific cost-based allocation;[355] and

WHEREAS, CCPUG argues that it is inappropriate to allow ENO to include any and all revenue requirements for newly constructed or acquired capacity or the expenses related to new PPAs and new LTSAs ENO may enter into through a PPCACR Rider.[356] CCPUG argues that doing so would inappropriately allow ENO to include these costs without review or further action by the Council other than the initial estimated revenue requirement for newly constructed or acquired capacity.[357] CCPUG recommends that the proposed tariff be modified so that no revenue requirement for newly constructed to acquired capacity or no expenses for new PPAs or LTSAs may be included without action by the Council and without an opportunity for the Council to

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[351] *Id.* at 97.
[352] *Id.*
[353] *Id.*
[354] *Id.*
[355] Ex. No. AP-3 at 19:3-5.
[356] Ex. No. CCPUG-1 at 53:8-11.
[357] *Id.* at 53:11-14.

review the reasonableness of the transactions and agreements as well as setting forth a process to allow intervenors to review the transactions and agreements as well as the revenue requirements and expenses that will be included in the rider;[358] and

WHEREAS, the Advisors argue that while a rider to permit contemporaneous recovery of PPA and LTSA costs may be appropriate, the scope of the rider should not be so broad as to encompass any as-yet unknown non-fuel revenue requirements related to construction and/or acquisition of new capacity, new PPA, or new LTSA.[359] Proposed PPCACR Rider is not necessary to allow ENO a reasonable opportunity to recover its prudently incurred costs related to future ENO-owned capacity additions, because mechanisms exist to allow ENO the opportunity to recover such costs.[360] Such non-fuel costs for new acquisitions, once known and measurable, are more appropriately addressed in a general rate proceeding where all of ENO's cost categories and magnitude of costs are considered in total.[361] The PPCACR Rider would set a separate rate for incremental ENO-owned capacity additions and ensure ENO exact cost recovery, which constitutes inappropriate single-issue ratemaking;[362] and

WHEREAS, the Advisors argue that because the timing of any new construction and/or acquisition of new capacity, new PPA, or new LTSA is currently unknown as are the magnitude of any costs associated with the unknown future capacity additions, consideration in this instant base rate proceeding is not appropriate.[363] Additionally, the proposed PPCACR Rider allocates costs to rate classes using a Base Rate Revenue Requirement allocation factor, but since the costs proposed for recovery in this rider are non-fuel costs associated with production plant, a Production

[358] *Id.* at 54:5-11.
[359] Advisors' Initial Brief at 98, citing Ex. No. ADV-1 at 32:3-6.
[360] *Id.*, citing Ex. No. ADV-6 at 86:9-11.
[361] *Id.*, citing Ex. No. ADV-1 at 32:6-10.
[362] *Id.*, citing Ex. No. ADV-6 at 17-7:2.
[363] *Id.* at 98-99, citing Ex. No. ADV-1 at 32:10-13.

Demand Allocation Factor would be more appropriate and consistent with how the costs would be anticipated to be allocated in a base rate proceeding;[364] and

WHEREAS, the Code of the City of New Orleans, Sec. 158-732(c) requires ENO to seek Council approval for taking an interest in a transmission or generation facility or for entering into a PPA whose costs generally exceed 2% of the rate making value of ENO's property.[365] ENO can reasonably request that the Council approve cost recovery relief as part of any such application; therefore, there is no need at this time for the Council to approve such currently unknown costs to be recovered through the proposed PPCACR Rider.[366] To that end, the Advisors recommend that (1) costs for non-fuel revenue requirements related to construction and acquisition of new capacity, fixed costs associated with new PPAs, and costs associated with new LTSAs not be provided automatic recovery in the proposed PPCACR Rider, and that the name of the rider be changed to the Purchase Power Cost Recovery Rider ("PPCR"); (2) that the new PPCR Rider collect the difference (positive or negative) between the estimated PPA capacity and LTSA expenses in the new base rates from this proceeding (Schedule A costs) and the actual PPA capacity and LTSA expenses incurred by ENO on a monthly basis; (3) costs recoverable in the PPCR Rider be limited to costs associated with ENO's existing PPAsand long term service agreements including: Grand Gulf UPSA, EAL Resource PPA, Riverbend PPA, Ninemile 6 PPA, Algiers Slice of System PPA, and LTSA Costs associated with the following facilities: UPS, Ninemile 6, Perryville 1 (Algiers SOS PPA), and Acadia (Algiers SOS PPA); (4) the Schedule A costs identified in the new PPCR be those costs identified in the HSPM Exhibit OT-2, broken down by month; (5) the new PPCR Rider allocate costs to rate classes using the Production Demand Allocation Factor determined in

[364] *Id.* at 99, Ex. No. ADV-1 at 32:13-18.
[365] *Id.*, Ex. No. ADV-8 at 3-6.
[366] *Id.*, Ex. No. ADV-2 at 6-9.

this proceeding; and (6) the Council implement a new PPCR Rider that is based on the redline of ENO's proposed PPCACR Rider provided as Exhibit No. JWR-6 attached to Exhibit No. ADV-1;[367] and

WHEREAS, CCPUG objects that the proposed PPCACR Rider would inappropriately allow near automatic recovery of new capacity costs and costs of newly-constructed generating assets without full certification review by the Council.[368] CCPUG also argues that the PPCACR is also unnecessary as any new investment costs it would recover may be recovered through ENO's proposed E-FRP;[369] and

WHEREAS, CCPUG states it is not opposed to the Advisors' recommendations for the (to-be-renamed) Purchased Power Cost Recovery Rider ("PPCR");[370] and

WHEREAS, the Council agrees with the concerns stated by the Advisors and CCPUG; and

WHEREAS, the Council directs ENO to revise its proposed PPCACR Rider in accordance with the Advisors' recommendations for a PPCR Rider; and

MISO COST RECOVERY RIDER

WHEREAS, consistent with the combination of Legacy ENO and Algiers customers, ENO proposes a combined MISO Cost Recovery Rider that for the most part mimics the current separate MISO Riders, though certain now inapplicable costs have been eliminated from the formula.[371] The combined MISO Cost Recovery Rider would be re-determined annually and subject to annual true-ups beginning in 2020.[372] ENO also proposed to use this combined rider in

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[367] *Id.* at 99-100, citing Ex. No. ADV-1 at 33:14-34:16.
[368] CCPUG Reply Brief at 30.
[369] *Id.*
[370] *Id.* at 31.
[371] Advisors' Initial Brief at 100, citing Ex. No. ENO-55 at 31; Ex. No. ENO-41 at 40:12-15.
[372] *Id.*, citing Ex. No. ENO-55 at 31; Ex. No. ENO-41 at 40:15-18.

the 2019 MISO Rider filing in order to facilitate the transition from the two current riders and two sets of rates to the combined rates expected to become effective in August 2019.[373] The general purpose of the MISO Cost Recovery Rider is to define the procedure by which ENO shall implement and adjust rates contained in the designated rate classes for recovery of the costs, including, but not limited to, costs charged to ENO pursuant to the FERC-approved MISO Open Access Transmission Energy and Operating Markets Tariffs that are not recovered via the FAC.[374] The Combined MISO Rider revenue requirement would reflect the following costs and revenues: (1) estimated Net MISO Charges or Credits (*i.e.*, MISO charges and credits for which recovery has not been requested separately through the FAC), and (2) a true up of actual revenues to actual costs, including carrying charges;[375] and

WHEREAS, the Advisors have reviewed the proposed rider and supporting testimony and did not find any reference errors or calculation errors.[376] The Advisors' analysis indicates that the proposed rider is consistent with the directions given to ENO by the Council in Resolution No. R-17-504 to develop a single set of proposed tariffs applicable to all customers, that its cost allocation is appropriate and that the cost categories and adjustment calculations that ENO removed are no longer necessary.[377] Therefore, the Advisors recommend that the Council approve the MISO Cost Recovery Rider as proposed by ENO;[378] and

WHEREAS, the Council approves the combined MISO Cost Recovery Rider as proposed by ENO; and

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373 *Id.*, citing Ex. No. ENO-55 at 31-32.
374 *Id.* at 101, citing Ex. No. ADV-1 at 29:10-15.
375 *Id.*, citing Ex. No. ENO-41 at 40:23-41:3.
376 *Id.*, citing Ex. No. ADV-1 at 29:18-19 and 30:13-14.
377 *Id.*, citing Ex. No. ADV-1 at 3-13.
378 *Id.*

ELECTRIC RESIDENTIAL CUSTOMER CHARGE

WHEREAS, ENO's proposes to increase the electric residential customer charge from the current $8.07 to a proposed $15.53 customer charge.[379] According to ENO, its cost of service study showed customer-related costs of service per residential customer to be $21.07 a month.[380] ENO witness Talkington stated that customer-related costs that do not vary with monthly changes in a customer's demand or energy usage should be recovered through a fixed monthly customer charge.[381] ENO witness Thomas added that higher fixed charges relative to volumetric rate structures provide more stability to ENO's revenues;[382] and

WHEREAS, AAE urges the Council to reject ENO's proposal to nearly double the level of the current residential customer charge and assert that a $15.53 customer charge is "extreme" and fails to reflect the true nature of gradualism in utility ratemaking, as evidenced by national trends in residential fixed charges;[383] and

WHEREAS, Mr. Barnes asserted that ENO's calculated customer unit cost is inflated by including numerous costs that bear little or no relationship with costs (i) associated with connecting a customer to the grid, or (ii) which vary directly with the number of customers being served.[384] Barnes also charged that a higher customer charge would lower the volumetric kWh rate, thus diluting customer incentives to use less energy;[385] and

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[379] Ex. No. ENO-45 at 26.
[380] *Id.*
[381] *Id.* at 23.
[382] Ex. No. ENO-2 at 62.
[383] Initial Brief of the Alliance for Affordable Energy and Sierra Club at 20, July 26, 2019 ("AAE/Sierra Club Initial Brief").
[384] *Id.*
[385] *Id.* 15-19.

WHEREAS, AAE recommended a customer charge of $8.13/month, "in order to properly reflect cost causation, avoid significant adverse impacts on customers with lower incomes, and support the Council's policies on energy efficiency;"[386] and

WHEREAS, the Advisors' recommended a $10 per month electric customer charge, which is a relatively small increase that recognizes that costs have increased since the 2008 rate case but also minimizes the impact on low-use customers.[387] The Advisors expressed serious concern that ENO's proposed $15.21 electric customer charge is almost a 100% increase above the existing customer charge, and that large change would have a substantial adverse impact on low-use customers.[388] Advisors' witness Prep recommended a small increase in the residential customer charge to moderate the bill impact on customers with lower or minimal usage.[389] Mr. Prep further testified that the remainder of that portion of the residential cost of service would be recovered through kWh usage;[390] and

WHEREAS, the Council shares the concerns expressed by AAE and the Advisors regarding the impact of ENO's proposed customer charge on low income and low use customers; and

WHEREAS, the Council also finds that ENO's proposal, which is an almost 100% increase above the existing customer charge, fails to reflect the concept of gradualism in ratemaking and is therefore, excessive; and

WHEREAS, the Council accepts AAE's argument that an increase to the residential customer charge would reduce customers' incentives to use less energy. Such a result would be

[386] AAE/Sierra Club Initial Brief at 31.
[387] Ex. No. ADV-3 at 60.
[388] Advisors' Initial Brief at 62.
[389] Ex. No. ADV-3 at 60.
[390] *Id.*

inconsistent with the Council's long-standing policy of supporting and increasing energy efficiency in New Orleans; and

WHEREAS, the Council finds that not altering the Company's current $8.07 customer charge is consistent with addressing AAE's and the Advisors' concern regarding the potential for significant adverse impacts on low income customers and supportive of the Council's long-standing policy of supporting and increasing energy efficiency; and

WHEREAS, the Council rejects ENO's proposed customer charge of $15.53 and finds that the Company's $8.07 customer charge shall remain unchanged as a result of the evidence presented in this proceeding; and

AMI CUSTOMER CHARGE

WHEREAS, ENO proposes a customer charge for its costs in deploying and implementing ENO's Advanced Metering Initiative approved by the Council in Docket No. UD-16-04. Specifically, ENO proposes an electric AMI charge and a gas AMI charge to be collected through Rider AMICE and Rider AMICG, respectively;[391] and

WHEREAS, ENO contends that the number of customers ENO serves, in large part, drives the level of the costs associated with AMI. Therefore, these costs should be recovered through a customer charge (rather than base rates) so that a customer bears only the cost that the customer causes. The charges are intended to recover the net present value of the electric and gas AMI revenue requirements. Any differences in the revenue resulting from the customer charges and the actual costs of AMI would be reconciled through the proposed electric and gas FRPs. As proposed, the charges are intended to recover the net present value of the electric and gas AMI revenue

[391] Revised Application at 37-38.

requirements. Any differences in the revenue resulting from the customer charges and the actual costs of AMI would be reconciled through the proposed electric and gas FRPs; [392] and

WHEREAS, both the gas and the electric AMI charges would change annually, beginning on January 1, 2020. The initial proposed monthly customer charges would be $2.95 for electric customers and $0.60 for gas customers. In January of 2020, the proposed monthly customer charges would be $3.67 for electric customers and $0.96 for gas customers;[393] and

WHEREAS, after 2020, the gas AMI charge would decline annually until 2029 when it terminates. Similarly, the electric AMI charge would decline annually until it terminates in 2035;[394] and

WHEREAS, AAE argues that ENO's proposed fixed monthly charge is unreasonable[395] because AMI is not "typical" metering.[396] AAE contends that "fixed customer charges should recover the cost of connecting a customer to the grid.[397] AAE argues that advanced metering and the associated incremental costs above traditional meters are not strictly necessary for the customer to be connected to the grid.[398] It also argues that a non-advanced meter and associated infrastructure can do so at lower costs, but AMI is used for much more than measurement of a customer's consumption for billing purposes;"[399] and

WHEREAS, instead AAE recommends the Council adopt a volumetric rate design in order to support energy efficiency, protect the greater portion of lower income customers from disproportionate impacts, and distribute the costs and benefits of AMI more equitably;[400] and

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[392] Id. at 38.
[393] Ex. No. AAE-3 at 30, citing Ex. No. ENO-4, Exhibit JBT-9.
[394] Revised Application at 37-38.
[395] Ex. No. AAE-3 at 31-34.
[396] *Id.* at 31.
[397] AAE/Sierra Club Initial Brief at 42.
[398] *Id.*
[399] Ex. No. AAE-3 at 31.
[400] *Id.* at 34.

WHEREAS, AAE further notes that a volumetric AMI charge would cause lower usage customers to pay less towards AMI deployment, when those same customers act to reduce their energy consumption or peak period demands, higher usage customers still receive a greater portion of the benefits of the associated cost savings.[401] Therefore, according to AAE, while higher usage customers pay more under a volumetric design, they also receive more in return;[402] and

WHEREAS, the Advisors contend that ENO's proposed per-customer charges in Rider AMICE and Rider AMICG are intended to allow ENO recover substantially all of its AMI-related costs through these riders rather than base rates.[403] The Advisors' proposed allocation of AMI cost responsibility is based on the net benefits identified in AMI Docket No. UD-16-04 including "greater grid resiliency in the distribution network, improved outage and reliability performance, improved grid planning for modifications and improvements, DSM programs, time differentiated pricing, and specially designed customer options, among other system and customer benefits."[404] The Advisors also assert that ENO's proposed allocation of cost responsibility for AMI-related costs on a per-customer basis through a rider is inappropriate single-issue ratemaking.[405] Specifically, because the pace of AMI deployment is known, measurable, and reasonably within ENO's control and related costs are similarly known and measurable, the use of a rider is unnecessary and singling-out AMI costs for recovery through riders constitutes inappropriate single-issue ratemaking.[406] Accordingly, the Advisors recommend the Council deny ENO's request for Rider AMICE and Rider AMICG; and

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[401] *Id.*
[402] *Id.*
[403] Advisors' Initial Brief at 94; *citing* Ex. No. ADV-6 at 83-84.
[404] Advisors' Reply Brief at 20.
[405] Advisors' Initial Brief at 94; *citing* Ex. No. ADV-6 at 83-84.
[406] *Id.*

WHEREAS, CCPUG argues against the Advisors' recommended methodology for assigning responsibility among the rate classes for costs related to ENO's AMI deployment. CCPUG favors ENO's proposed per-customer methodology and labels the Advisors' recommended benefits-based allocation methodology base rate "socialization."[407] In contrast, the Advisors dispute that their recommendation is a form of cross-subsidization, asserting that it is based on a careful analysis of resulting net-benefits.[408] Moreover, the Advisors assert that the ENO/CCPUG proposal to recover AMI-related costs on a per-customer basis is flawed because ENO's proposed allocation of AMI costs on the basis of numbers of customers weighs disproportionately on residential customers.[409] In addition, the ENO has long-asserted that AMI is intended to provide many functions and benefits beyond those of existing meters that serve the sole function of generating billing information.[410] Thus, the Advisors correctly note that a per-customer allocation of AMI-related costs would result in cross-subsidization benefiting large and industrial customers at the expense of residential and small commercial customers; and

WHEREAS, the Council agrees with the Advisors' contention that the ENO/CCPUG proposal would result in cross-subsidization benefiting large and industrial customers at the expense of residential and small commercial customers and reject the ENO/CCPUG proposal to recover AMI-related costs on a per-customer basis because as ENO has argued since its initial proposal in Docket No. UD-16-04. AMI provides many functions and benefits beyond existing meters' sole function to generate billing information.[411] As ENO has repeatedly made clear, the approximately $80 million AMI capital investment is more than just new meters, as the benefits

[407] CCPUG Initial Brief at 78.
[408] Ex. No. ADV-3 at 28:10-12.
[409] *Id.* at 28:10-19
[410] *Id.* at 28:13-16.
[411] Ex. No. AAE-5 at 31.

of AMI include greater resiliency in the distribution network, improved outage and reliability performance, improved grid planning for modifications and improvements, DSM programs, and time differentiated pricing. Moreover, as noted above, ENO agrees that the Advisors' proposed prospective treatment of known and measurable costs and attendant revenue change would mitigate the need for the proposed AMI Riders;[412] and

FORMULA RATE PLANS

WHEREAS, ENO proposed electric and gas FRPs with an implementation date of 2020 and an initial term of three years that incorporates many features of the predecessor FRP approved by the Council in Resolution No. R-09-136, including the basic structure that evaluates whether the Company's rates fall within a bandwidth around the authorized ROE (midpoint) established by the Council, with annual evaluations that prospectively adjust rates to the midpoint;[413] and

WHEREAS, ENO also proposed several categories of FRP changes - for the E-FRP: (1) changes to the target Evaluation Period Cost of Equity ("EPCOE") to incorporate the proposed RIM Plan's adjusted ROE formula; (2) changes to accommodate the Energy Smart Program; (3) changes to implement the Decoupling Pilot Program (4) a new provision for an interim Rate Adjustment for NOPS non-fuel revenue requirement; (5) a new provision for changes in income tax rates; (6) a change to the "Extraordinary Cost Changes" provision related to the revenue trigger; and (7) a new provision for Rider PPCACR Transitional Items;[414] and for the gas FRP: (1) changing the filing date to April 30, with the initial rate adjustment to be effective for the first billing cycle in September; (2) the treatment of changes in the tax rate; and (3) increasing the

[412] Ex. No. ENO-3 at 9:3-7; ENO Reply Brief at 48.
[413] Ex. No. ENO-55 at 20.
[414] Ex. No. ENO-41 at 29:11-21.

revenue requirement impact trigger to the Extraordinary Cost Changes section from $750,000 in the previous FRP to $1 million;[415] and

WHEREAS, both of ENO's FRPs, which are based largely on the FRP's previously approved by the Council, include, among others, the following features:

- Use of the previous calendar year as the Evaluation Period (*i.e.*, historic test year);
- Use of the authorized ROE set in this proceeding as the target Evaluation Period Cost of Equity ("EPCOE");
- A deadband of plus or minus 50 basis points centered on the EPCOE, in which there would be no change in rates;
- A formula that adjusts the FRP revenue level for the Evaluation Period to prospectively earn the EPCOE, commonly referred to as "resetting to the midpoint," if the Earned Rate of Return on Equity ("EROE") is above or below the deadband;
- A seventy-five day review period;
- A specified dispute resolution procedure; and
- A three-year term;[416] and

WHEREAS, the use of an FRP mechanism and several aspects of ENO's proposed FRP mechanism are undisputed by the parties. The Council finds that the undisputed elements of the FRP are reasonable and should be approved; and

WHEREAS, the following aspects of ENO's proposed FRP mechanism are disputed by the parties: (1) whether total utility operating revenues and costs should be included in the FRP calculation; (2) whether forward-looking adjustments for known and measurable changes in the rate effective period should be included in the FRP calculation; (3) whether ENO's proposed RIM should be included in the FRP; (4) whether ENO should update the inputs to the class cost of

[415] Ex. No. ENO-55 at 21; Ex. No. ENO-41 at 48:15-22.
[416] Ex. No. ENO-41 at 28:14-29:7; Ex No. ENO-3 at 7:3-20.

service studies in the E-FRP decoupling adjustment and how rates are reset if ROE is outside the FRP bandwidth; and (5) whether and how costs related to NOPS should be included in the FRP mechanism; and

(1) *__Whether Total Utility Operating Revenues and Costs Should Be Included in the FRP Mechanism__*

WHEREAS, the Advisors recommend that the Council should evaluate whether ENO is under-earning or overearning in the FRP by evaluating the total utility cost of service, including total ENO revenues and expenses, rather than limiting the FRP evaluation to base rate costs and revenues. That approach to evaluating total utility revenue requirements is consistent with the Advisors' approach establishing a fully allocated cost of service; and

WHEREAS, the Advisors concur with ENO's proposals to exclude Energy Smart costs, Lost Contributions to Fixed Costs ("LCFC"), and the utility incentive from the E-FRP mechanism,[417] and with ENO's proposed provisions regarding (i) the effect of any tax rate changes, (ii) increasing the revenue requirement trigger in the Extraordinary Cost Changes Section from $2 million to $6 million, and (iii) realigning future purchase power capacity recovered in the Advisors' proposed PPCR to the E-FRP;[418] and

WHEREAS, ENO opposes the inclusion of all revenues and expenses, including riders, in the Electric and Gas FRPs, similar to its approach in the Revised Application to use a cost of service limited to base rates. ENO argues that no evidence has been offered to show that any other regulator in the country requires utilities to include rider revenues and costs recovered through those riders when setting base rates.[419] ENO argues that the Advisors' proposed method would not change the level of ENO's base revenue requirement to be recovered in base rates, would not

[417] Ex. No. ADV-3 at 76:3-4; Advisors' Initial Brief at 105.
[418] Ex. No. ADV-3 at 76:14-17; Advisors' Initial Brief at 105.
[419] ENO Initial Brief at 102.

give the Council a better understanding of ENO's financial performance, and could have the effect of shifting cost responsibility among the rate classes, although ENO's base revenue requirement from a total Company perspective would be unaffected;[420] and

WHEREAS, Air Products also opposes the Advisors' proposal to include total revenues and expenses in FRP evaluations, arguing that Riders should not be included because they have nothing to do with whether ENO is under-earning or over-earning.[421] Air Products believes a distortion is created: "...by including FAC revenues in the base revenue requirement used to adjust revenues after an FRP review has been conducted, then fuel revenues that recover cost that have made no contribution to the under- or over recovery will be part of the factor used to apportion any revenue changes, which will produce a distorted result;"[422] and

WHEREAS, the Advisors argue that to avoid single issue ratemaking, the total cost of service should be examined to adjust total revenues, not just to set base rates.[423] The Advisors argue that ENO's arguments are without merit, that base revenue requirement is only a portion of the total cost of service; the Council should evaluate ENO's financial performance and earned ROE based on its total cost of service; and a "shift" in cost responsibility is meaningless when the evaluation does not consider total costs. Moreover, the Advisors argue that decisions regarding cost recovery mechanisms, such as base rates and riders, follow the evaluation of the utility's total revenue requirement, therefore, no distortion is created.[424] Under the Advisors' proposal, allocations of fixed costs and variable costs and the cost responsibility supporting customer class

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[420] *Id.*
[421] Air Products' Initial Brief at 32.
[422] *Id.* at 26. (Emphasis added.)
[423] Advisors' Reply Brief at 32.
[424] *Id.* at 34.

revenue requirements are determined separately such that fuel costs and FAC revenues would not distort the fixed costs revenue requirement; and

WHEREAS, the Advisors argue that in an FRP filing, a comprehensive evaluation of the earned ROE compared to the Council-approved ROE requires that all costs and revenues be included.[425] The Advisors also argue that, contrary to the assertion of ENO that there would be double-counting of cost and revenues, as long as all costs and revenues are supported by the financial reports of the system accounts, and each program adjustment is supported with explanation and workpapers, double-counting of costs and revenues should be avoided.[426] In addition, the Advisors argue, Directive 6 of Resolution No. R-16-03 requires that all utility fixed costs should be included in the decoupling revenue adjustment, regardless of the revenue recovery mechanism used to recover any specific fixed (non-fuel) costs;[427] and

WHEREAS, the Council finds that in an FRP filing, a comprehensive evaluation of the earned ROE compared to the Council-approved ROE requires that all costs and revenues be included; and

(2) *Whether Forward-Looking Adjustments for Known and Measurable Changes Should be Included in the FRP Calculation*

WHEREAS, the Advisors also recommend an additional provision under FRP Attachment C, Evaluation Period Adjustments, paragraph 8. Other that would state: "ENO may propose other known and measurable costs that are supportable and expected to be incurred in the prospective 12 months following the FRP Evaluation Period;"[428] and

425 Ex. No. ADV-5 at 23:11-13; Advisors' Initial Brief at 107; Advisors' Reply Brief at 34.
426 Ex. No. ADV-5 at 24:1-6; Advisors' Initial Brief at 107; Advisors' Reply Brief at 34.
427 Ex. No. ADV-5 at 24:6-9; Advisors' Initial Brief at 108; Advisors' Reply Brief at 34.
428 Ex. No. ADV-3 at 78:9-13; Advisors' Initial Brief at 106; Advisors' Reply Brief at 35.

WHEREAS, the Advisors also recommend that the FRP provision for an extraordinary cost change should be included as a proforma adjustment prospective to the FRP Evaluation Period pursuant to the Advisors' proposed revision to Attachment C, Adjustments paragraph 8, if such occurs during the period.[429] Otherwise, the extraordinary costs may be considered for interim recovery, and included in the ROE bandwidth evaluation of the next FRP;[430] and

WHEREAS, ENO agreed with the Advisors' position that incorporating forward-looking proforma adjustments to account for known and measurable costs (and attendant revenue changes) in the calendar year following the FRP evaluation period in a properly structured FRP would address ENO's concerns regarding regulatory lag to a great degree.[431] ENO also agreed that the Advisors' proposed prospective treatment of known and measurable costs and attendant revenue change would mitigate the need for the Electric and Gas AMI Charge Rider and the DGM Rider, although ENO witness Thomas argued for a provision to implement those riders in the event the FRP terminates after the initial three-year term;[432] and

WHEREAS, CCPUG opposes the Advisors' proposal to include projected costs in the FRP, arguing that the inclusion of projected costs – which may or may not ever be incurred – undermines a utility's incentive to operate effectively and economically.[433] CCPUG argues that allowing ENO to include a "wish list" of investments it may make in the coming year in its current rates is fraught with peril and ripe for abuse.[434]

WHEREAS, the Advisors argue that CCPUG ignores the requirement that projected costs be "known and measurable."[435] The Advisors contemplate that in order to be known and

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[429] Ex. No. ADV-3 at 77:16-20; Advisors' Initial Brief at 106; Advisors' Reply Brief at 35.
[430] Ex. No. ADV-3 at 77:20-21; Advisors' Initial Brief at 106; Advisors' Reply Brief at 35.
[431] Ex. No. ENO-3 at 8:9-12; Ex. No. ENO-4 at 13:21-23; ENO Reply Brief at 48.
[432] Ex. No. ENO-3 at 9:3-7; ENO Reply Brief at 48.
[433] CCPUG Initial Brief at 69; CCPUG Reply Brief at 34.
[434] *Id.*
[435] Advisors' Reply Brief at 35.

measurable,[436] such costs either (i) would have already been presented to and approved by the Council prior to inclusion in an open and transparent proceeding that allows for public participation, such as ENO's projected AMI costs, or (ii) that such costs would be clearly supported in ENO's detailed budgeting process.[437] The Advisors argue that their proposal is by no means a blank check for ENO to simply include projected costs it would like to incur for projects that have not been reviewed and approved by the Council in a proceeding that allows all interested parties to have input.[438] As such, the Advisors recommend that the Council review such out-of-period proforma adjustments to ensure they were indeed accomplished.[439] The Advisors explain that if ENO were shown to have abused this ratemaking treatment, the Council could then take appropriate action.[440] Thus, the Advisors argue, the concerns raised by CCPUG that ENO will be able to collect a return on a "wish list" of investments that are never made are unfounded.[441] The Advisors recognize that ENO is undertaking a significant level of investment in its system and that regulatory lag could be a sufficient obstacle and believe that this proposal will sufficiently mitigate the impact of regulatory lag, without the need for unnecessary riders, while still providing ENO an incentive to be efficient and allowing the Council oversight of ENO's investments;[442] and

WHEREAS, ENO argues that CCPUG's assertion that new measures are unnecessary because traditional FRPs provide near real-time recovery of costs actually incurred is supported only by a vague conclusory statement in testimony that traditional FRPs eliminate much of the regulatory lag without any analysis to clarify what this statement means.[443] By way of contrast,

[436] "Known and measurable" is discussed in the following testimony in this docket: Ex. No. ENO-41 at 2; Ex. No. CCPUG-2 at 9; Ex. No. ADV-1 at 2; Ex. No. ADV-2 at 11; and Ex. No. ENO-40 at 18.
[437] Ex. No. ADV-6 at 66:4-6; Advisors' Reply Brief at 35-36.
[438] Advisors' Reply Brief at 36.
[439] *Id.*
[440] *Id.*
[441] *Id.*
[442] *Id.*
[443] ENO Reply Brief at 48.

ENO argues, its own witness provided an analysis showing the cash flow effects of recovering a large, long-term capital project with multiple plant closings throughout the year;[444] and

WHEREAS, CCPUG witness Kollen argues that if the Council approves an E-FRP and/or GFRP implementation date of 2020 based on a calendar year 2019 Evaluation Period, it should require ENO to exclude all proforma adjustments for 2019.[445] If such proforma adjustments are not excluded for 2019, then CCPUG objects to an E-FRP implementation date of 2020 and recommends that it be delayed until 2021;[446] and

WHEREAS, ENO disagrees with the suggestion of CCPUG witness Kollen that the proposed FRPs should not use calendar year 2019 as the first evaluation period. ENO argues that to use 2019 as the first evaluation period would be consistent both with prior Council practice and LPSC practice;[447] and

WHEREAS, the Council finds that an electric and gas FRP should be implemented for a three-year period with an appropriate ROE and a bandwidth of +/- 50 basis points, to begin with a May 2020 filing covering a calendar year 2019 test year; and

WHEREAS, the Council finds that ENO may propose other known and measurable costs that are supportable and expected to be incurred in the prospective 12 months following the FRP Evaluation Period, during which the FRP rate adjustment would be effective and that an extraordinary cost change should be included as a proforma adjustment prospective to the FRP Evaluation Period, or be considered for interim recovery and included in the ROE bandwidth evaluation of the next FRP; and

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444 *Id.* at 48-49.
445 Ex. No. CCPUG-1 at 45:12-14; 51:12-26; Ex. No. CCPUG-2 at 25:1-7.
446 Ex. No. CPPUG-1 at 45:14-15.
447 Ex. No. ENO-3 at 12:12-20, citing Resolution Nos. R-03-272 and R-09-136; ENO Reply Brief at 51-52.

(3) *Whether ENO's Proposed RIM Should Be Included in the FRP*

WHEREAS, ENO proposes a RIM within its electric FRP. ENO states that it is proposing its RIM Plan because it recognizes that its reliability performance has not met the expectations of ENO, its customers, and the Council.[448] ENO's intention is to align the earnings component of its base rates to its distribution reliability performance.[449] ENO proposes that its electric ROE (which ENO proposes to be 10.75%) would be reduced by 25 basis points (to 10.5%) then, if ENO's performance improves, as measured through ENO's Distribution System Average Interruption Frequency Index ("SAIFI"), it would return to the baseline ROE (10.5%) and thereafter ENO's SAIFI based on the Evaluation Period data would then translate into a number of positive or negative basis points (maximum of 25) to be added to the baseline ROE.[450] ENO states that its expected year-end 2018 SAIFI score is expected to be 1.65.[451] ENO proposes that if its SAIFI improves to 1.24 the adjustment would be zero, a score of 1.40 or worse would warrant a 25 basis point decrease from 10.75%, and an improvement to 1.05 would warrant a 25 basis point increase from 10.75%.[452] ENO argues that this proposal directly addresses the reliability issue, balances the interests of stakeholders, is transparent, and is administratively straightforward to implement;[453] and

WHEREAS, CCPUG argues that the proposed RIM should be rejected by the Council.[454] CCPUG argues that given ENO's unacceptably poor electric system reliability over the last few years, the Council should not under any circumstances approve a regulatory incentive mechanism

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[448] Ex. No. ENO-1 at 23:3-6.
[449] *Id.* at 23:11-12.
[450] *Id.* at 24:1-26:2.
[451] *Id.* at 28:5-6.
[452] *Id.* at 28:3-16; Ex. No. ENO-41 at 31:2-23.
[453] *Id.* at 26:5-19.
[454] Ex. No. CCPUG-3 at 50:7-8.

that provides the possibility of ENO earning a higher ROE for improved system reliability.[455] CCPUG argues that reliable service is part and parcel of every utility company's duty, including ENO, under the Regulatory Compact.[456] In other words, in return for its monopoly status and the absence of competition, its power of eminent domain, and the opportunity to earn an almost guaranteed ROR, the utility's service must be reliable.[457] CCPUG also argues that ENO has admitted that it does not require an incentive to provide reliable service.[458] CCPUG argues that the Council should set base level performance attainment levels in this proceeding of 1.16 for SAIFI and 113.8 for SAIDI.[459] CCPUG suggests a 25 basis point reduction penalty for underperformance and no incentive for improved performance;[460] and

WHEREAS, Air Products also opposes the RIM, arguing that the mechanism is conceptually flawed because it would reward ENO for doing what it is supposed to be doing in the first place -- namely, providing reliable service.[461] Air Products urges the Council to reject the proposed RIM, or, in the alternative that the RIM should not apply to customers who take service at the transmission level;[462] and

WHEREAS, the Advisors argue that as a public service company, ENO should prudently manage its electric utility, including making prudent expenditures and investments, and SAIFI is one metric for ENO's performance.[463] They argue ENO should not require an incentive to act prudently and achieve reasonable results for stakeholders.[464] The Advisors also argue that even if

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[455] Ex. No. CCPUG-1 at 50:10-13.
[456] *Id.* at 50:13-14; CCPUG Reply Brief at 36.
[457] Ex. No. CPPUG-1 at 50:14-17.
[458] CCPUG Reply Brief at 36, quoting City Council Hearing Transcript, 122:2-8 (June 18, 2019).
[459] Ex. No. CCPUG-3 at 52:20-23.
[460] *Id.* at 52:14-18 and 53:2-5.
[461] Ex. No. AP-3 at 20:14-16; Air Products' Initial Brief at 36; Air Products' Reply Brief at 13-14.
[462] Ex. No. AP-2 at 21:5; Air Products' Initial Brief at 36; Air Products' Reply Brief at 14.
[463] Ex. No. ADV-1 at 15:2-4; Advisors' Initial Brief at 110.
[464] Ex. No. ADV-1 at 15:4-5; Advisors' Initial Brief at 110.

the Council were to decide to incentivize ENO to improve its reliability, the Advisors would not recommend the Council utilize an ROE adjustment to do so;[465] and

WHEREAS, the Advisors argue that there is not a direct relationship between ROE and distribution system performance and the ROE customarily affects ENO's return on all its investments, not just the investments in the distribution plant that is generally regarded as most closely related to many of ENO's reported service outages, which constitutes only 57.9% of ENO's net plant in service.[466] Moreover, they argue, the Council is currently investigating ENO's reliability performance in Council Docket No. UD-17-04, including consideration of what appropriate SAIFI and SAIDI standards should be as well as any appropriate incentives and penalty mechanisms related to those standards.[467] The Advisors argue that setting a target SAIFI level and incentive mechanism in this proceeding would be premature prior to the conclusion of the investigations being conducted in Docket No. UD-17-04.[468] Additionally, the Advisors note, the impacts on ratepayers of the proposed RIM are not insignificant. Under ENO's proposed RIM, they argue, if ENO were to succeed in improving its SAIFI performance sufficiently to allow its ROE to increase from 10.5% to 11.0%, the result would be that ENO is able to collect an additional approximately $2.7 million from its ratepayers.[469] The Advisors recommend that the Council not approve ENO's proposed RIM; and

WHEREAS, in response to the Advisors' argument that any minimum reliability standard should be addressed in Council Docket No. UD-17-04, ENO responds that it would be amenable to the Council setting ENO's electric ROE at 10.50% in this proceeding and directing the details

[465] Advisors' Initial Brief at 110.
[466] Ex. No. ADV-1 at 15:9-14; Advisors' Initial Brief at 110-111.
[467] Resolution No. R-17-427.
[468] Ex. No. ADV-1 at 16:10-17:2; Advisors' Initial Brief at 111.
[469] Ex. No. ADV-1 at 14:18-20; Ex. No. ADV-6 at 12:3-11; Advisors' Initial Brief at 111.

of a balanced financial incentive and penalty mechanism that would permit ENO's ROE to adjust above 10.50% be determined in Docket No. UD-17-04, which ENO anticipates would be resolved prior to the resetting of rates through the FRP;[470] and

WHEREAS, the Advisors argue that there is no need to consider ENO's proposed RIM further in Docket No. UD-17-04.[471] They argue that ENO's appropriate allowed-ROE will be established in this rate case, and the Council is considering whether or not to adopt minimum reliability performance standards in Docket No. UD-17-04.[472] The Advisors take the position that there is no need to consider ROE and minimum reliability performance standards in conjunction with each other,[473] because there simply is no direct relationship between the utility's ROE and distribution performance -- any adjustment to ROE would typically affect ENO's return on all of its plant, not just the distribution plant that is generally regarded as most closely related to many of ENO's reported service outages;[474] and

WHEREAS, ENO argues that its proposed RIM Plan is a transparent and straightforward approach towards achievement of certain reliability performance goals, making the earnings component of its rates contingent upon reliability performance.[475] ENO argues that a mechanism tying reliability performance to any financial outcome should be symmetrical and that if a financial value (*i.e.* penalty) can be ascribed to performance below the range, then a value exists for performance above the range.[476] ENO also argues that similar mechanisms have been implemented by regulators in other jurisdictions.[477] ENO writes:

[470] Ex. No. ENO-3 at 19:20-20:3.
[471] Ex. No. ADV-2 at 4:11-15; Advisors' Initial Brief at 111.
[472] Ex. No. ADV-2 at 4:6-8; Advisors' Initial Brief at 111-112.
[473] Ex. No. ADV-2. at 4:8-9; Advisors' Initial Brief at 112.
[474] Ex. No. ADV-2 at 4:9-5:4; Advisors' Initial Brief at 112.
[475] ENO Initial Brief at 52.
[476] *Id.* at 53.
[477] *Id.* at 52.

> Reliable service is ENO's goal, but providing reliable service comes at a cost; the question becomes what is the appropriate balance between the two. This is a tradeoff that regulators must factor into their decision-making on just and reasonable rates;[478]

and

WHEREAS, the Advisors argue that while ENO is correct that it is the job of the regulator to determine the point at which the incremental gains to be achieved by further increasing reliability are outweighed by the cost of doing so, reliable service is not merely a "goal" of the utility, rather, it is the fundamental purpose for which the utility exists.[479] They argue that ENO's attempt to extract further profit from ratepayers for merely improving its reliability to an acceptable level is distasteful at best.[480] The Advisors take the position that when coupled with ENO's proposal to change Section 11 Continuity of Service of ENO's Service Regulations,[481] and ENO witness Stewart's statement on the stand that she would not say ENO has a duty to provide safe and reliable electric service,[482] these arguments demonstrate a troubling attitude on ENO's part that reliability is somehow optional and the utility must be provided with an incentive to provide it;[483] and

WHEREAS, the Advisors oppose ENO's RIM proposal to tie its ROE to its reliability performance arguing that ENO's earnings component of its rates should not be contingent upon its reliability performance. They argue that the Council is not faced with a "tradeoff" and is not required to provide ENO with an incentive to increase reliability just because reliability comes with a cost, all of which will be recovered from ratepayers in any event;[484] and

[478] *Id.* at 54-55.
[479] Advisors' Reply Brief at 37.
[480] *Id.*
[481] Ex. No. ENO-6, at Ex. No. MPS-8 at 18.
[482] City Council Hearing Transcript, 114:17-18 (June 18, 2019).
[483] Advisors' Reply Brief at 37.
[484] *Id.* at 38.

WHEREAS, Air Products urges the Council to reject the proposed RIM, or in the alternative, to find that the mechanism should not be applied to transmission-level customers such as Air Products.[485] Air Products argues that its witness, Brubaker, testified that the RIM mechanism is conceptually flawed because it would reward ENO for doing what it is supposed to be doing in the first place -- namely, providing reliable service.[486] In apparent agreement with the Advisors testimony,[487] Air Products also notes that ENO is proposing, through its Distribution Grid Modernization Rider, to charge customers for the cost of upgrading its distribution grid, which would in turn be expected to improve reliability -- thus, customers (not ENO shareholders) would have already paid for the improved reliability of ENO's distribution system.[488] Air Products also argues that to the extent the Council approves the RIM plan, it should not apply to customers who take service at the transmission level because they will not benefit from improvements in reliability on the distribution system since the entire focus of reliability improvement is at the distribution level;[489] and

WHEREAS, AAE and Sierra Club also oppose the RIM Plan, noting that ENO fails to even recognize its responsibility to provide reliable service to New Orleans ratepayers, and that ENO is effectively asking to be rewarded for operating its distribution system in the manner to which ratepayers are entitled, but have not been receiving for years.[490] AAE and Sierra Club argue that the Council should reject ENO's attempt to "do an end run" around the Council's ongoing investigation in UD-17-04.[491] In agreement with Advisors' testimony,[492] they also argue that

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[485] Air Products' Initial Brief at 35.
[486] *Id.*; Ex. No. AP-3 at 20:16-21:3.
[487] Ex. No. ADV-1 at 15:10-19.
[488] Air Products' Initial Brief at 35; Ex. No. AP-3 at 21:9-11.
[489] Air Products' Initial Brief at 35; Ex. No. AP-3 at 21:11-13 and 22:3-4.
[490] AAE/Sierra Club Initial Brief at 46-47.
[491] *Id.* at 48.
[492] Ex. No. ADV-1 at 15:10-19.

ENO's ROE affects its return on all investments, not just the distribution plant that is most closely related to many of ENO's reported service outages, and ROE is based on market performance of proxy companies, not SAIFI values, so the ROE is not the best mechanism to incentivize ENO's distribution-related performance given its broad impact on ENO's overall rates.[493] AAE and Sierra Club also allege that ENO has been overearning on its ROE for a number of years, and during that period had a dismal record regarding distribution system outages, so there is no reason to believe that allowing ENO to over-earn is the best way to incentivize the Company.[494] Finally, they note that FERC has declined incentives to utilities "for doing what it is supposed to do, *i.e.*, to adequately maintain its facilities in a prudent cost-effective manner," and argue that New Orleans ratepayers should not be required to pay extra for a service they are entitled to by virtue of ENO's status as the monopoly provider of electric service;[495] and

WHEREAS, the Council finds that ENO's proposed RIM Plan should be denied, and the issue of reliability standards and any penalties for failing to meet them should be taken up in Council Docket No. UD-17-04 rather than in this rate case; and

(4) *Whether ENO Should Update the Inputs to the Class Cost of Service Studies in the E-FRP Decoupling Mechanism, and How Rates are Reset if ROE is Outside the FRP Bandwidth*

WHEREAS, the Advisors argue that the electric FRP decoupling revenue adjustment for each customer class should be determined by comparing the evaluation period fixed & variable revenue by class with the FRP evaluation period allocation of total ENO fixed and variable revenue requirement;[496] and

[493] *Id.*
[494] *Id.*
[495] *Id.* at 48-49, quoting *New England Power Pool*, 97 FERC ¶ 61,093 at 61,477 (2001); *order on reh'g*, 98 FERC ¶ 61, 249 (2002), Reply Brief of the Alliance for Affordable Energy and Sierra Club at 19, Aug. 9, 2019 ("AAE/Sierra Club Reply Brief").
[496] Ex. No. ADV-3 at 78:6-8.

WHEREAS, Air Products also opposes the Advisors' proposal that whenever an E-FRP evaluation is conducted, the external allocation factors be updated, arguing that this would make the process unnecessarily complex, expensive, contentious and inefficient and would not prevent significant changes in rates for customers in rate classes with only a few customers as a result of decoupling;[497] and

WHEREAS, the Advisors explain that after determining the allocated (fixed and variable) cost responsibility from the total cost of service, the E-FRP adjustment by customer class can be determined by the difference between the evaluated customer class total cost of service and the customer class actual total revenue and there would be no issue of double recovery.[498] The Advisors argue that updating external allocation factors with current billing determinants is not complex and reflects changes in customer usage necessary to maintain fairness in the customer class decoupling revenue adjustments; and

WHEREAS, the Council agrees with the Advisors that the E-FRP decoupling revenue adjustment for each customer class should be determined by comparing the evaluation period fixed and variable revenue by class with the FRP evaluation period allocation of total ENO fixed and variable revenue requirement; and

WHEREAS, the Advisors recommend that the Council approve a three-year FRP with an appropriate ROE and a bandwidth of +/- 50 basis points,[499] to begin with a May 2020 filing covering a calendar year 2019 test year;[500] and

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[497] Ex. No. AP-4 at 12:3-11; Air Products and Chemicals, Inc.'s Post-Hearing Reply Brief at 22-23, Aug. 9 2019 ('Air Products' Reply Brief").
[498] Ex. No. ADV-3 at 24:9-12.
[499] *Id.* at 77:8-9.
[500] *Id.* at 77:9-11.

WHEREAS, Air Products opposes an FRP adjustment resetting rates to EPCOE[501] (the midpoint of the ROE bandwidth), but rather proposes that if the EROE is above the upper bandwidth, the revenue adjustment be only partially moved toward the upper bandwidth (60% of the way toward the upper bandwidth), such that ENO is able to retain some of the benefits of the efficiencies it gained.[502] When earnings are below the lower edge of the bandwidth, Air Products recommends that the adjustment be 60% of the way toward the lower bandwidth;[503] and

WHEREAS, ENO opposes this proposal and disagrees arguing that such a mechanism would result in ENO not having an opportunity to recover its costs and would always result in rate adjustments that set rates at a level below ENO's revenue requirement and provide ENO no opportunity to recover its costs;[504] and

WHEREAS, the Advisors oppose Air Products' proposal and support the complete reset of rates when the earned ROE falls outside the bandwidth.[505] The bandwidth is set at a reasonable range to allow ENO to keep a reasonable amount of value from efficiencies while protecting ENO against incurring too much risk from investing in and/or supporting and promoting energy efficiency, demand response, rooftop solar and the like.[506] Not allowing rates to be reset when they fall below the bandwidth would give ENO an incentive to oppose those programs, and allowing ENO to keep more of the profits of above-bandwidth revenues would provide ENO with too much incentive to increase kWh sales rather than to promote conservation;[507] and

WHEREAS, the Council agrees with the Advisors' assessment of Air Products' proposal and finds it should be rejected; and

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501 Ex. No. AP-3 at 22:13-14.
502 *Id.* at 23:13-21.
503 *Id.* at 24:8-11.
504 ENO Reply Brief at 52.
505 Advisors' Reply Brief at 40.
506 *Id.*
507 *Id.*

(5) *Whether and How Costs Related to NOPS Should Be Included in the FRP Mechanism*

WHEREAS, ENO proposes to begin recovering the estimated first year revenue requirement associated with the NOPS in the first billing cycle of the month after the NOPS enters commercial operation.[508] ENO testified that it expects the NOPS to enter commercial operation in January 2020,[509] although that date has since been moved later into year 2020; and

WHEREAS, ENO also proposes to recover the estimate through an interim rate adjustment under ENO's proposed E-FRP.[510] Assuming that the Council approves an E-FRP, the Company requests that the Council confirm in this proceeding that an interim rate adjustment under ENO's proposed E-FRP is the contemporaneous cost recovery mechanism to be used to recover the NOPS first year revenue requirement;[511] and

WHEREAS, CCPUG argues that it is reasonable to include an interim rate adjustment in the E-FRP to recover the costs of NOPS, but that the costs included in the calculation of the interim rate adjustment are not reasonable for three reasons.[512] First, ENO's ROE is excessive – (ENO's proposed 10.5% ROE should be replaced by CCPUG proposed 9.35% ROE or whatever other ROE the Council authorizes.[513] Second, the NOPS depreciation rate and depreciation expense are excessive, and should be based on a CCPUG proposed service life of 50 years, instead of the Company's assumed service life of 30 years.[514] The third reason the costs included in the calculation of the interim adjustment are unreasonable is that CCPUG believes that ENO intends

[508] Ex. No. ENO-2 at 67:11-13 (HSPM).
[509] *Id.* at 67:13-14 (HSPM).
[510] *Id.* at 67:18-19 (HSPM).
[511] *Id.* at 67:20-23 (HSPM).
[512] Ex. No. CCPUG-1 at 46:8-11.
[513] *Id.* at 46:13-20.
[514] *Id.* at 47:1-19.

to maintain the NOPS first year revenue requirement until the next general rate case, with no revenue requirement reduction due to greater accumulated depreciation and ADIT;[515] and

WHEREAS, in Council Docket No. UD-16-02, in which the Council approved NOPS, the Advisors proposed that the cost recovery of the NOPS investment be accomplished contemporaneously as a second step rate adjustment subsequent to the 2019 effective date of the revised rates from the instant docket.[516] Specifically, the Advisors believe that the NOPS interim rate adjustment could be a provision in the proposed FRP, providing contemporaneous recovery from the date of NOPS commercial operation ("COD").[517] The Advisors have proposed that proforma adjustments be included in the FRP for the 12-month period subsequent to the FRP evaluation period, which would encompass calendar year 2020 for the first FRP.[518] According to the Company, NOPS is expected to enter commercial operation in early 2020.[519] The Advisors argue that if the NOPS updated revenue requirement filing is not included as a prospective proforma adjustment in the proposed FRP filed in April 2020, the NOPS in-service rate adjustment, beginning with the month following COD, would be effective until NOPS costs are included in the ROE bandwidth evaluation of the following FRP.[520] If the NOPS updated revenue requirement filing is included as a 2020 proforma adjustment in the proposed FRP filed in April 2020, the NOPS in-service rate adjustment would be effective with the COD until the FRP rate adjustment is implemented in September 2020, at which time NOPS cost recovery would be included in the FRP rate adjustment;[521] and

[515] *Id.* at 47:20-48:4.
[516] Resolution No. R-18-65 at 176.
[517] Advisors' Initial Brief at 44.
[518] Ex. No. ADV-5 at 24:18-25:2.
[519] Ex. No. ENO-2 at 67:13-14.
[520] Ex. No. ADV-5 at 25:3-6.
[521] *Id.* at 25:4-10.

WHEREAS, ENO objects to Advisors' witness Prep's approach. The Company asserts that the potential exists that the bandwidth calculation may prevent ENO from recovering 100% of the NOPS costs.[522] ENO argues that "it would be illogical to permit 100% recovery of the NOPS costs in the interim rate adjustment but later reduce that recovery because of the FRP bandwidth mechanics."[523] Therefore, the Company believes that the first-year revenue requirement should be reflected in its entirety in the FRP Rate Adjustment and any subsequent cost changes be subject to the bandwidth calculation;[524] and

WHEREAS, the Advisors urge the Council to adopt witness Prep's recommendation regarding NOPS cost recovery and the inclusion of NOPS in the proposed FRP revenue adjustment.[525] The first-year revenue requirement associated with NOPS should be included in rates as an in-service rate adjustment, beginning with the month after NOPS enters commercial operation. The Advisors argue that this rate adjustment shall remain in place until NOPS costs are included in the costs of an FRP evaluation period and in the ROE bandwidth calculation.[526] The Advisors disagree with ENO's argument that it should be permitted to recover the initial year of NOPS costs without being included in an ROE evaluation.[527] As with all other costs included in an FRP evaluation of earnings, ENO has the opportunity to earn its approved ROE rather than a guarantee that it will recover 100% of NOPS costs;[528] and

WHEREAS, the Advisors recommend that the interim Rate Adjustment for NOPS non-fuel revenue requirement be included under the proposed FRP Attachment C, paragraph 8, or in the following FRP within the bandwidth evaluation, depending on the commercial operation date,

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[522] Ex. No. ENO-3 at 48:5-6.
[523] *Id.* at 48:6-8.
[524] *Id.* at 48:8-10.
[525] Advisors' Initial Brief at 45.
[526] *Id.* at 45.
[527] *Id.*
[528] *Id.*

and that the FRP provision include an allocation of NOPS costs based on the rate case production demand allocation factor, rather than total base rate costs;[529] and

WHEREAS, CCPUG argues that ENO's proposal will lead to excessive recovery in the first year and every year thereafter until base rates are reset, because the ROR is excessive, the depreciation rate and depreciation expense are excessive, and the revenue requirement is generally at the maximum for the first year and then declines due to the accumulation of book depreciation and the tax savings from accelerated tax depreciation;[530] and

WHEREAS, CCPUG recommends ENO apply a 9.35% ROE to the E-FRP, that the first year revenue requirement for NOPS be reduced to reflect a 50-year service life, and that ENO be ordered to reduce the revenue requirement for NOPS each year to reflect an additional year of depreciation and deferred income tax expense;[531] and

WHEREAS, ENO suggested that the Council not determine the parameters for recovery of the NOPS revenue requirement in this proceeding, but wait until ENO makes its proposed rate filing prior to the in-service date of NOPS based on the estimated first NOPS revenue requirement.[532] CCPUG opposes this suggestion and argues that the Council should decide the issue in this case;[533] and

WHEREAS, AAE and Sierra Club oppose the NOPS adjustment in its entirety, arguing that because a presiding judge in Civil District Court issued a bench ruling voiding Resolution No. R-18-65, the construction of NOPS does not have the approval of the Council.[534] As AAE and Sierra Club are well aware, the Council appealed this ruling, and thus, that matter is not yet final.[535]

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[529] Ex. No. ADV-3 at 77:12-16.
[530] CCPUG Initial Brief at 68; Ex. No. CCPUG-1 at 46:8-48:4.
[531] CCPUG Initial Brief at 69; Ex. No. CCPUG-1 at 48:15-20.
[532] Ex. No. ENO-3 at 48.
[533] Ex. No. CCPUG-2 at 29:9-30:13.
[534] AAE/Sierra Club Initial Brief at 53.
[535] Advisors' Reply Brief at 52.

The Advisors propose that to the extent that the matter has not yet become final at the time that the Council issues a resolution in this rate case, any NOPS adjustment approved by the Council should be conditioned upon the construction of NOPS and associated costs having been approved through a final judgment of the Council;[536] and

WHEREAS, after considering all of the arguments and evidence related to this issue, the Council agrees with the Advisors proposal that proforma adjustments should be included in the FRP for the 12-month period subsequent to the FRP evaluation period, which would encompass calendar year 2020 for the first FRP.[537] The Council also finds that if the NOPS updated revenue requirement is included as a prospective proforma adjustment in the bandwidth evaluation of the proposed E-FRP filed in April 2020, the NOPS in-service rate adjustment, beginning with the month following COD, would be effective until NOPS cost recovery is included in the E-FRP revenue adjustment of the first FRP. The Council further finds that if the NOPS updated revenue requirement filing is not included as a prospective proforma adjustment in the proposed E-FRP filed in April 2020, the NOPS in-service rate adjustment, beginning with the month following COD, would be effective until NOPS costs are included in the ROE bandwidth evaluation of the following E-FRP;[538] and

WHEREAS, the Council finds that this course of action is consistent with the approach to evaluate the total utility cost of service and avoid single issue ratemaking; and

WHEREAS, the Council finds it reasonable to avoid future uncertainty and additional litigation costs by the parties not to defer consideration of the NOPS adjustment until a future date, but rather, as the Advisors suggest, to approve a NOPS adjustment with an instruction to ENO that

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[536] *Id.*
[537] Advisors' Initial Brief at 43-44; Ex. No. ADV-5 at 24:18-25:2.
[538] Advisors' Initial Brief at 44; Ex. No. ADV-5 at 25:3-6.

no actual costs should be flowed through that adjustment to ratepayers until such time as the construction of NOPS and the associated costs have been approved through a final judgment of the Council; and

WHEREAS, the Council finds that the interim Rate Adjustment for NOPS non-fuel revenue requirement be included under the proposed E-FRP Attachment C, paragraph 8, or in the following E-FRP within the bandwidth evaluation, depending on the commercial operation date; and

WHEREAS, the Council finds that the E-FRP provision should include an allocation of NOPS costs based on the rate case production demand allocation factor, rather than total base rate costs; and

DECOUPLING

WHEREAS, the Advisors explain that in Resolution No. R-16-03, ENO was ordered to include in its next base rate case filing a proposal for an electric utility full decoupling mechanism as a three-year pilot program, to begin with the implementation of rate changes arising from the Combined Rate Case; and

WHEREAS, the Advisors also argue that Resolution No. R-16-03 requires that all utility fixed costs should be included in the decoupling revenue adjustment, regardless of the revenue recovery mechanism used to recover any specific fixed (non-fuel) costs;[539] and

WHEREAS, the Advisors argue that Resolution No. R-16-03 also requires (i) that the fixed cost revenue requirement should be determined on an allocated basis for each customer class, (ii) that the allocation methodology should be applied consistently on an annual basis to determine

[539] Ex. No. ADV-5 at 24:6-9.

the decoupling revenue adjustments by customer class, (iii) and that the fixed-cost customer rate class allocation factor should be updated annually (with current billing determinants);[540] and

WHEREAS, ENO proposes a Decoupling Pilot Program within the electric FRP, through a four-step process to be applied only if a rate adjustment is necessary under the terms of the rider.[541] Under the decoupling proposal, the fixed and variable cost revenue requirements would be recovered from each rate class consistent with the allocation methodology used in the baseline rate case.[542] In the first step, the Baseline Fixed Cost Revenue Requirement and the Variable Cost Revenue Requirement would be determined.[543] The second step would be to allocate each Rate Class's Evaluation Period Base Revenue (and FRP Revenue, if any) between Fixed Revenue and Variable Revenue using the Baseline Revenue Requirement.[544] The third step would be to compute each rate class's Evaluation Period Fixed and Variable Revenue Deficiency or Excess.[545] The fourth and final step would be to calculate the Rate Adjustment for each rate class;[546] and

WHEREAS, under ENO's decoupling proposal, the revenue adjustments would be the difference between actual E-FRP evaluation period customer class base rate revenues and the E-FRP electric base rate revenue requirements allocated to customer classes using customer class base rate revenues approved by the Council in the instant docket; and

WHEREAS, under ENO's decoupling proposal, the E-FRP/decoupling base rate adjustment for each rate class would be calculated from each rate class's E-FRP evaluation period

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[540] *Id.*
[541] Ex. No. ENO-55 at 20-21; Ex. No. ENO-41 at 32:23-33:2.
[542] Ex. No. ENO-55 at 21.
[543] Ex. No. ENO-41 at 34:12-17.
[544] *Id.* at 36:6-8.
[545] *Id.* at 36:16-18.
[546] *Id.* at 37:3-7.

fixed and variable base rate revenue deficiency or excess, and applied as a percent of base rate revenue;[547] and

WHEREAS, ENO's decoupling proposal would not use cost allocation factors updated for each E-FRP evaluation period, and assumes the proportions of customer class fixed and variable base rate revenue requirements to be fixed (based on those values in the instant docket) for each of the E-FRP evaluation periods;[548] and

WHEREAS, AAE witness Morgan recommends four changes to ENO's decoupling proposal: (1) remove it from the effects of the FRP deadband; (2) clarify that it will only operate on either (a) revenues from customer billing charge billing determinants or minimum bill requirements in tariffs; or (b) revenues collected under tariff riders that are subject to full reconciliation; (3) clarify that the comparison is between the most recent approved revenues and the actual revenues, allocated to rate class/schedules per approved allocation factors, and not to a calculation of required allocated revenues that includes changes in costs during the decoupling period and (4) authorize ENO to calculate the difference between actual and authorized through-based revenues for fixed recovery on a monthly basis during any year, applying a Council-set carrying charge rate evenly to balances owed customers and owed ENO;[549] and

WHEREAS, AAE witness Morgan agrees that she did not participate in any of the Council's decoupling proceedings leading to the adoption of the Council's decoupling resolution, Resolution No. R-16-103.[550] She maintains, however, that decoupling should focus only on revenues, not expense, and that revenue decoupling is always backward looking - a true-up for

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[547] *Id.* at 36:16-18; 37:3-7.
[548] Ex. No. ENO-55 at 21; Ex. No. ENO-41 at 34:12-17.
[549] Ex. No. AAE-1 at 3:11-23; Ex. No. AAE-2 at 2:6-3:7, 9:16-21, 16:16-22; AAE Reply Brief at 16.
[550] Ex. No. AAE-2 at 3:15-4:1.

what actually happened compared to what was expected to happen.[551] AAE argues that any decoupling mechanism should operate separately from any FRP, be backward-looking in reconciliation, remove the need for any LCFC and ensure that there are no gaps that could penalize ENO for achieving the most energy efficiency it can;[552] and

WHEREAS, the Advisors recommend that the full decoupling mechanism should be approved for the three-year electric FRP term, that the total allocated costs of service for each customer class should be included in the decoupling revenue adjustment, and that the customer rate class allocation factors should be updated annually (with current billing determinants);[553] and

WHEREAS, the Advisors concur with ENO's recommendation that a decoupling adjustment be applied only if the E-FRP revenue adjustment is outside the bandwidth,[554] but recommend that the decoupling revenue adjustment be applied consistently to all customer classes based on the E-FRP evaluation period total revenue requirements of each customer class;[555] and

WHEREAS, the Advisors propose the following steps: (i) the "baseline" customer class revenue requirements in the instant Docket be updated with a new baseline of customer class fixed and variable revenue requirements in the E-FRP; (ii) the E-FRP fixed and variable total revenue requirements be determined for each customer class by an allocation of costs and a return component based on the rates of return corresponding to the customer class revenues set in the instant docket; (iii) the fixed and variable revenue deficiencies/excesses be determined for each customer class by comparing the E-FRP customer class total revenue requirements with the customer class evaluation period total revenues; and (iv) the customer class decoupling

[551] *Id.* at 4:14-15 and 5:8-9; AAE Reply Brief at 16.
[552] Ex. No. AAE-2 at 8:10-18.
[553] Ex. No. ADV-3 at 80:1-4.
[554] Ex. No. ADV-3 at 79:3-4.
[555] *Id.* at 79:4-7.

adjustments be applied within each customer class with updated billing determinants excluding the customer charge;[556] and

WHEREAS, ENO argues that its proposed decoupling approach is the only decoupling approach consistent with Resolution No. R-16-103 and accompanies by detailed explanatory testimony, a complete rate schedule setting forth the decoupling approach with exhibits, and a detailed example, and that no other party provided a proposal as comprehensive as ENO's;[557] and

WHEREAS, ENO argues (i) that the Advisors' assignment of the different required before-tax rates of return on rate base to each customer/rate class was done under no objective standard that can be replicated,[558] and (ii) that the proposed revenue by rate class approved in this proceeding be used to allocate ENO's revenue requirement in future FRP evaluation reports instead of developing customer/rate class revenue requirements from updated cost allocations and customer/rate class rates of return;[559] and

WHEREAS, ENO argues that there could be unintended consequences if a decoupling mechanism were to include all customer classes, particularly classes with few customers.[560] The Advisors argue, however, that concern of unintended consequences related to a customer class with few customers is without merit because updating allocation factors and billing determinants with each FRP will accommodate any shifts in customers and usage within these classes; and

WHEREAS, ENO also argues that it has significant concerns with the Advisors' proposal that the decoupling adjustment be performed by applying the same allocation methodology approved in this proceeding, and that ENO provide a new COS Study each year by updating the

[556] *Id.* at 79:9-11 and 78:6-8.
[557] ENO Reply Brief at 94.
[558] Ex. No. ENO-42 at 20:6-21:9, *see also*, ENO Reply Brief at 94.
[559] Ex. No. ENO-42 at 22:3-4.
[560] Ex. No. ENO-13 at 2:8-15 and 4:11-13.

allocation factors for each customer class with then-current customer data.[561] ENO argues that it would substantially undermine the purposes and efficiencies of an FRP and there would be minimal benefit to be gained from developing updated allocation factors and presenting a fully developed COS Study each year.[562] ENO also argues that the Advisors' proposal would substantially undermine the purposes and efficiencies of an FRP by creating an inefficient use of resources and significant additional work.[563] ENO argues that FRP's streamline the rate setting process by eliminating the usual contentious debate around the allocation of the revenue requirement to the various rate classes and the rate design for three to five years, which is allowed because, typically, there are no substantial changes in operations from year to year that would materially affect cost allocations among customer classes.[564] ENO argues that it will be very labor intensive and require numerous resources for ENO to develop the allocation factors for the FRP that would be required under the Advisors' proposal;[565] and

WHEREAS, Air Products argues that the structure of ENO's and other parties' decoupling mechanisms poses a substantial risk of a highly disruptive change in revenues for customers in classes that have only a few customers (Master-Metered Nonresidential, Large Electric High Voltage and Large Interruptible Service) because the mechanism essentially would guarantee fixed cost recovery from those classes regardless of the level of purchases by customers in those classes.[566] According to Air Products, a modest change in the level of business operations, and hence the amount of power required from ENO, could cause a very disruptive increase to those customers;[567] and

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[561] Ex. No. ENO-42 at 14:16-15:3.
[562] *Id.* at 15:3-6.
[563] *Id.* at 15:3-20.
[564] *Id.* at 15:12-19.
[565] *Id.* at 16:9-21.
[566] Air Products' Initial Brief at 10.
[567] *Id.*

WHEREAS, Air Products' witness Mr. Brubaker recommended that one of two solutions be applied to address the consequences that a decoupling adjustment could have on rate classes with only a few customers.[568] Either customer classes with only a few customers should be excluded from any decoupling mechanism, or there should be a maximum change of 10% in the average charge per kWh between rate cases to customers in those classes;[569] and

WHEREAS, the first recommendation of Mr. Brubaker is to exclude from the decoupling mechanism those classes with only a few customers.[570] As Mr. Brubaker points out, the revenues of these rate classes with only a few customers amount to less than 3% of total base rate revenues, so this exclusion would not materially impact the operation of a decoupling mechanism;[571] and

WHEREAS, in the alternative, Air Products asserts that should the Council not want to exempt any customer rate classes from the decoupling mechanism, it should adopt Mr. Brubaker's recommendation to cap the percentage change in average revenue per kWh between rate cases that result from the application of the decoupling mechanism to 10% for individual customers in rate classes Master Metered Non-Residential, Large Electric High Voltage and Large Interruptible Service, which would greatly reduce the potential for highly disruptive changes in these classes rates;[572] and

WHEREAS, Air Products requests that customer classes with few customers, including rate classes Master Metered Non-Residential, Large Electric High Voltage and Large Interruptible Service, either be exempt from the decoupling adjustment or have their exposure to changes in rates between rate cases resulting from the decoupling adjustment capped at 10%;[573] and

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[568] *Id.* at 41.
[569] *Id.* at 11.
[570] *Id.*
[571] *Id.*
[572] *Id.* at 42.
[573] *Id.* at 43.

WHEREAS, the Advisors argue that the decoupling mechanism should operate within the E-FRP, and should apply to proforma revenue requirements and billing determinants in the FRP rate effective period to reduce regulatory lag and remove the need for LCFC;[574] and

WHEREAS, the Advisors also argue that the concern of unintended consequences related to a customer class with few customers is largely without merit because updating allocation factors and billing determinants with current customer data in each E-FRP will accommodate any shifts in customers or usage within these classes, and the customer class rates of return determined by the customer class revenues set by the Council in the instant Docket would be the basis for the customer class return component in the FRP.[575] Consequently, ENO's argument regarding no objective standard that can be replicated for the different ROR on rate base for each customer/rate class is without merit; and

WHEREAS, the Advisors maintain that updated allocation factors are necessary to reflect the change in usage patterns related to increased energy efficiency, distributed energy resources, renewables including solar, new products and equipment, and other current impacts affecting usage that were not as much of a concern in years previous;[576] and

WHEREAS, the Advisors also argue that implementing the Advisors' decoupling recommendations will not require a level of effort comparable to a cost allocation study in a general rate case, since using the same methodologies and models, with no requirement for two test periods or weather normalization, minimal updating of weighting factors, and no change to the use of the external and internal allocation factors in the cost of service model will not undermine the efficiencies of the E-FRP;[577] and

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[574] Ex. No. ADV-5 at 29:3-30:4.
[575] *Id.* at 27:17:2.
[576] *Id.* at 27:6-10.
[577] *Id.* at 25:25:16-19 and 26:18-27:1.

WHEREAS, despite its assertion that its proposal is the only one that complies with Resolution No. R-16-103,[578] ENO proposes that it not be required to meet the requirement of Resolution No. R-16-103 that it recalculate a fixed-cost customer rate class allocation factor or factors each year consistent with the cost allocation methodology used in this proceeding and use those factors to allocate the FRP evaluation period electric revenue requirement to each rate class.[579] ENO argues that (1) strictly following the rate class cost allocation from the cost of service study allocation factors would cause a disruptive increase in cost responsibility for the Residential Rate Class, and (2) the Council had not adopted such a rate class cost allocation in its last two rate cases.[580] Instead, ENO proposes that the FRP Evaluation Period electric revenue requirement be allocated consistent with the relative allocation of the base electric revenue among the rate classes approved by the Council, absent some material change that indicated that relative allocation should be modified;[581] and

WHEREAS, the Advisors argue that ENO's claim regarding a "disruptive increase in cost responsibility for the Residential Rate Class" is not supported by any analysis. If the cost allocation methodologies accepted by the Council in this docket are simply updated with current billing determinants, a disruptive increase in cost responsibility is implausible, as is defining "some material change" in ENO's decoupling proposal; and

WHEREAS, the Council finds that it thoroughly examined the issue of decoupling in a transparent docket open to all interested parties, and in which the AAE actively participated in Docket No. UD-08-02. The outcome of that examination was the adoption by the Council of a decoupling mechanism in Resolution No. R-16-03. Thus, the Council finds that the appropriate

[578] ENO Reply Brief at 94.
[579] ENO Initial Brief at 100.
[580] *Id.*
[581] *Id.* at 100-101.

consideration in this rate case is whether or not ENO's decoupling proposal complies with the Council's instructions in Resolution No. R-16-03; it is not an appropriate proceeding for parties to take "another bite at the apple" as to what the appropriate structure of the decoupling mechanism is. That was decided in Resolution No. R-16-03, and the Council finds that no party has raised a sufficient reason for the Council to re-open the decisions made in Resolution No. R-16-03 in this proceeding; and

WHEREAS, while AAE urges the Council to reject the concept that stakeholders who failed to participate in a previous process should "be forever barred from weighing in on an issue,"[582] that is not what is at issue in this proceeding. The Council must strike a balance between striving to continually make improvements to its regulations and providing sufficient stability in its regulations that regulated entities can understand what they must do to comply with the Council's regulations. It is not beneficial to any party for the Council's regulations to be a constant "moving target." Under the facts presented in this case, the Council finds that the AAE and other interested parties had sufficient opportunity to advocate for their desired decoupling structure in Docket No. UD-08-02 and have not offered sufficient cause for the Council to take the unusual step of altering its regulations through a rate case; and

WHEREAS, the Council finds that a full decoupling mechanism should be filed with each electric E-FRP evaluation, with total allocated costs of service for each customer class included in the decoupling revenue adjustment, and the customer rate class allocation factors be updated annually with current billing determinants; and

WHEREAS, the Council finds that the decoupling adjustment be applied to all customer classes if the E-FRP revenue adjustment is outside the bandwidth; and

[582] AAE Reply Brief at 17.

WHEREAS, the Council has carefully considered Air Products' arguments and alternative proposals with respect to the potential impact of ENO's proposed decoupling mechanism on rate classes with only a few customers and believe that Air Products' concerns are valid; and

WHEREAS, the Council finds that some protection should be provided for those rate classes (Master Metered Non-Residential, Large Electric High Voltage and Large Interruptible Service) having only a few customers to mitigate the potential exposure of those rate classes to highly disruptive changes in rates that may occur as a result of the decoupling mechanism approved in this case; and

WHEREAS, for rate classes Master Metered Non-Residential, Large Electric High Voltage and Large Interruptible Service, a decoupling revenue adjustment cap of 10% shall apply to each of the three annual FRP evaluation period revenue adjustments provided that the total electric utility FRP revenue adjustment for that evaluation period does not exceed 10%; and

WHEREAS, the Council finds that a new baseline of customer class fixed and variable revenue requirements be determined in each E-FRP from an allocation of costs and a return component based on the rates of return corresponding to the customer class total revenues set in the instant docket. Any adjustments that may be needed to the relative rates of return will be such that those adjustments move the relative customer class rates of return toward the utility's rate of return based on the weighted average cost of capital; and

WHEREAS, the Council finds that the revenue deficiencies/excesses be determined for each customer class by comparing the E-FRP customer class total revenue requirements with the customer class evaluation period total actual revenues, with the decoupling adjustments applied within each customer class using updated billing determinants excluding the customer charge; and

WHEREAS, the Council finds that the decoupling adjustment should apply to proforma revenue requirements and billing determinants in the E-FRP rate effective period, based on updated allocation factors and billing determinants in each E-FRP; and

WHEREAS, to the extent any undisputed element of ENO's decoupling proposal is not addressed herein, the Council has reviewed it and found it reasonable, and it is approved as proposed by ENO; and

GREEN POWER OPTION

WHEREAS, ENO proposed a "green pricing proposal" in this case pursuant to Resolution No. R-18-97.[583] Under ENO's proposed Green Power Option ("Rider GPO"), a voluntarily enrolled customer would be able to match some or all (*i.e.*, 100%) of their electricity usage with renewable energy certificates ("RECs") sourced from renewable energy sources like wind and solar;[584] and

WHEREAS, a REC represents the environmental benefits of 1 MWh of renewable energy.[585] ENO argues that by purchasing and pairing RECs with their electricity service, retail customers can use and receive the benefits of that renewable electricity.[586] ENO argues that RECs are used across the country as a low-risk option to support renewable energy and meet renewable energy usage goals;[587] and

WHEREAS, ENO's proposed Rider GPO would be open to all customers and allow them the option of matching 100%, 50%, or 25% of their electricity usage each month with RECs.[588] ENO explains that nationally, demand for green pricing options provided by utilities has increased

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[583] Ex. No. ENO-55 at 41; Ex. No. ENO-19 at 41:4-16.
[584] Ex. No. ENO-55 at 41; Ex. No. ENO-19 at 40:9-11.
[585] Ex. No. ENO-55 at 41; Ex. No. ENO-19 at 40:13-15.
[586] Ex. No. ENO-55 at 41.
[587] Ex. No. ENO-55 at 41; Ex. No. ENO-19 at 40:18-41:2.
[588] Ex. No. ENO-55 at 41; Ex. No. ENO-19 at 43:15-17.

substantially in recent years, and that, according to surveys conducted by ENO, approximately 36% of ENO's customers have expressed interest in participating in a green power option;[589] and

WHEREAS, under the proposal, ESI's System Planning and Operations Organization ("SPO") would acquire and retire the RECs associated with the Green Power Option.[590] ENO proposed that the offering be certified by "Green-e", which, ENO explains, is an independent consumer protection organization that offers certification and verifies the integrity of RECs through the entire chain of custody, so customers can be confident in their purchase;[591] and

WHEREAS, ENO's proposed green power option would be available to all customer classes and there will be no limit on the number of customers that can participate.[592] Under ENO's proposal, there would be no minimum contract term for participation, though customers who withdraw would not be eligible to return until after the seventh month following their withdrawal.[593] Customers would be allowed to change their election no more than one time in any six-month period;[594] and

WHEREAS, ENO's proposed price for the Green Power Option would incorporate REC prices (as driven by the national market), a small contingency to account for fluctuations in REC prices and vendor support costs related to customer enrollment, customer education/marketing, and Green-e certification.[595] ENO proposed the following charges for each of the three options:[596]

Option	**GPO Election**	**Rate (per kWh)**
Tier One Option	25%	$0.015 per kWh

[589] Ex. No. ENO-19 at 41:17-42:12.
[590] *Id.* at 47:3-9.
[591] *Id.* at 44:1-4.
[592] *Id.* at 44:18-21 and 45:18.
[593] *Id.* at 46:6-10.
[594] *Id.* at 46:13-14.
[595] *Id.* at 47:12-21.
[596] *Id.* at 48:6-10.

Tier Two Option	50%	$0.0125 per kWh
Tier Three Option	100%	$0.01 per kWh

WHEREAS, the options would be priced at different amounts in order to encourage customers to choose to offset more of their usage with renewable energy.[597] ENO's proposed pricing is based on assumptions regarding participation levels over the first three years, and to the extent that actual participation levels and costs are significantly different than ENO's assumptions and/or change over time, ENO would seek pricing adjustments, though ENO does not anticipate that adjustments would be needed frequently;[598] and

WHEREAS, the Advisors estimate that under ENO's proposed rate, a 1,000 kWh per month customer (which is approximately the average residential customer) who chose the 100% Green Power Option would experience a surcharge on their bill of approximately $10/month.[599] The Advisors calculate that ENO would profit from Rider GPO, but not materially or over the long term, and conclude that the estimated O&M costs related to the GPO Rider do not constitute a substantial risk to ratepayers should ENO's actual costs be less.[600] The Advisors state that any collections in excess of actual expenses would be corrected for prospectively as part of any FRP evaluation;[601] and

WHEREAS, BSI opposes the Green Pricing Proposal because BSI believes it will neither lower rates, nor contribute to improving New Orleans' local economics nor its local

[597] *Id.* at 48:12-14.
[598] *Id.* at 49:6-11.
[599] Ex. No. ADV-6 at 71:13-14.
[600] *Id.* at 71:16.
[601] *Id.* at 71:18-72:1.

environmental footprint, and proposes that all Green Pricing funds be invested in CLEP instead;[602] and

WHEREAS, ENO argues BSI's claims that CLEP is superior to the Green Power Option are unsupported by any testimony and should be rejected;[603] and

WHEREAS, the Council observes that there are no funds set aside for the Green Power Option, rather, customers would on an individual basis, decide whether to participate, thus there are no "funds considered for Green Pricing" that can be directed to another purpose in the absence of a Green Power Option; and

WHEREAS, the Advisors recommend that the Council approve Rider GPO because it presents a valuable option for ratepayers who wish to offset the environmental impact of their electricity consumption while imposing substantially no costs or risks to non-participants.[604] The Advisors also recommend that the Council evaluate the programs' actual costs of operation as part of future rate actions, such as FRP evaluations, and take any further appropriate action at that time, including adjustments to Rider GPO's rates;[605] and

WHEREAS, AAE and the Sierra Club argue that ENO's proposed Rider GPO should be modified in two ways: (1) rather than using Green-e certified RECs to verify that green power is used, the Council should direct ENO to define explicitly green energy as actual clean resources, *i.e.*, solar, wind, and battery storage; and (2) the Council should direct ENO to include language in the Rider GPO tariff that expressly states that any costs or expenses not recovered from participants may not be recovered from ratepayers;[606] and

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[602] Building Science Innovators, LLC Post Hearing Brief at 25, July 26, 2019 ("BSI Initial Brief").
[603] ENO Reply Brief at 118.
[604] Ex. No. ADV-6 at 72:6-9.
[605] *Id.* at 72:12-15.
[606] AAE/Sierra Club Initial Brief at 52-53.

WHEREAS, with respect to the first point, AAE and Sierra Club argue that Green-e is not regulated by the Council and the Council has no control over what resources are designated as green resources.[607] They argue that this is a problem because some states may include energy generated from black liquor or waste to energy facilities in their renewables portfolio standards that ultimately determine whether a resources is "green" within that state or not. AAE and Sierra Club view these types of resources "unclean" and only want solar, wind, and battery storage resources to be included;[608] and

WHEREAS, ENO argues in response to the AAE and Sierra Club that Resolution No. R-18-97 simply required ENO to make a "proposal under which customers may voluntarily choose to have some or all of the electricity supplied by *renewable resources*" and did not otherwise define "renewable resources."[609] ENO argues that AAE submitted no testimony or evidence in support of its argument that the scope of allowed resources should be narrowed; and

WHEREAS, the Advisors note that the Council currently has an RPS rulemaking docket open, Council Docket No. UD-19-01, where the issue of what energy resources the Council would deem as eligible to be considered "renewable resources" is being actively considered.[610] Therefore, the Advisors believe it is premature for the Council to rule in this rate case what should and should not be considered an "eligible" resource for the Green Power Tariff.[611] The Advisors also argue that it would be unnecessarily burdensome for ENO to comply with and the Council to enforce two separate definitions of "renewable energy," one for the Rider GPO and different one

[607] *Id.* at 52.
[608] *Id.*
[609] ENO Reply Brief at 116, citing Resolution No. R-18-97, at P 9 (emphasis added).
[610] Advisors' Reply Brief at 53.
[611] *Id.* at 53-54.

for the RPS.[612] The Advisors agree, however, that only RECs that would otherwise satisfy the Council's definition of renewable resources are appropriate for inclusion in the program;[613] and

WHEREAS, ENO argues that Green-e is an independent consumer protection organization that verifies that the RECs procured by the Company are (a) sourced from facilities that meet quality criteria that has been endorsed by diverse stakeholder group; (b) marketed transparently and honestly; and (c) delivered exclusively to the purchaser of the REC, *i.e.,* that the renewable attribute of the generation is not used toward a state renewable energy mandate or otherwise double-counted.[614] ENO notes that Green-e has specific minimum criteria related to: facility online date, REC vintage, and eligible resource types, yet it also allows flexibility in design;[615] and

WHEREAS, the Advisors also argue that any program based upon RECs must utilize some method of certifying the RECs as green resources to ensure that the source of the REC is known and that the REC is not double-counted (*i.e.* both sold to ENO and used to satisfy the RPS requirement in the state in which it was generated, or sold to more than one customer).[616] Green-e is a nationally known and widely used service that performs such tracking and certification.[617] Therefore, the Advisors believe that use of Green-e certification, or a similar certification, for any RECs purchased by ENO for the Rider GPO would be appropriate.[618] Therefore, the Advisors recommend that the Council put in a requirement that RECs used for the Rider GPO must both (1) be certified by Green-e; and (2) conform to the definition of renewable resources ultimately

[612] *Id.* at 54.
[613] *Id.*
[614] ENO Reply Brief at 116.
[615] *Id.*
[616] Advisors' Reply Brief at 54.
[617] *Id.*
[618] *Id.*

adopted by the Council in Docket No. UD-19-01.[619] To the extent that there is not a final Council decision in Docket No. UD-19-01 prior to the implementation of the Rider GPO, the Advisors recommend that ENO be allowed to utilize any Green-e certified RECs until such time as the Council renders a decision in Docket No UD-19-01, at which point, ENO must conform its use of RECs to the Council's definition of renewable resources on a going-forward basis;[620] and

WHEREAS, the Advisors are concerned about the proposal to include storage as a renewable resource because storage is not inherently a renewable form of electricity.[621] The Advisors note that (1) storage does not actually generate any electricity, it merely stores electricity generated by a generator until a more advantageous time to utilize that electricity and (2) the electricity from any given storage battery may or may not have originally been generated by a renewable resource.[622] The Advisors note, for example, that although many home batteries are coupled with a rooftop solar unit, there is no requirement that they be, and homeowners can easily install a home battery that is simply charged with electricity from the local utility, which is a mix of any number of renewable and non-renewable resources.[623] Therefore, while the Advisors would not exclude from eligibility any RECs originally from an energy source that have passed through a storage battery, the Advisors recommend that any such REC be able to demonstrate that the original source from which the electricity was generated was in fact a renewable resource and that the REC be Green-e certified so that the renewable properties of the electricity cannot be double-counted;[624] and

619 *Id.*
620 *Id.*
621 *Id.*
622 *Id.* at 54-55.
623 *Id.* at 55.
624 *Id.*

WHEREAS, with respect to AAE and Sierra Club's second proposed modification, that ENO be required to include express language in the Green Power Option tariff that expressly states that any costs or expenses not recovered from participants may not be recovered from ratepayers, ENO argues that Resolution No. R-18-97 requires that "[t]he green pricing proposal should reflect *to a reasonable extent* ENO's incremental net cost to provide this option to customers."[625] ENO argues that its testimony demonstrates that the pricing has been designed such that it is "reasonably assured" that the price of the RECs and incremental costs of offering the product will be recovered from participants.[626] ENO also states that actual participation levels and costs will be monitored, and ENO will seek adjustments, subject to Council approval, if warranted;[627] and

WHEREAS, the Advisors advise the Council that AAE and Sierra Club's recommendation that ENO be required to include express language in the Green Power Option tariff that expressly states that any costs or expenses not recovered from participants may not be recovered from ratepayers is inconsistent with the regulatory doctrine that the utility must be allowed sufficient revenues to meet its operating expenses, provide its shareholders with a reasonable ROR and attract new capital.[628] The Advisors explain that such costs must be recovered from the utility's customers, either the customers participating in the program or the non-participating customers.[629] It is the Advisors' expectation that there will be enough interest in the program that there will be a sufficient number of participating customers to cover the program's costs, and that in the event that there are not, the costs would be *de minimis* as testified

[625] ENO Reply Brief at 117, citing Resolution No. R-18-97.
[626] *Id.*, citing Ex. No. ENO-19 at 48.
[627] ENO Reply Brief at 117, citing Ex. No. ENO-19 at 49.
[628] Advisors' Reply Brief at 55, citing *Cent. Louisiana Elec. Co. v. Louisiana Pub. Serv. Comm'n*, 508 So. 2d at 1364-65, citing *So. Cent. Bell Tel. Co. v. Louisiana Pub. Serv. Comm'n*, 352 So. 2d at 967.
[629] Advisors' Reply Brief at 55.

to by ENO witness Owens.[630] The Advisors argue that because there is value to customers in being given an option, such as the Rider GPO, even if those customers do not take advantage of it, it would be reasonable for non-participating customers to bear such *de minimis* costs in the event the program does not prove to be popular;[631] and

WHEREAS, the Advisors, however, would not endorse a blank check to ENO to pass through any and all costs, whether reasonable or not, or to run an unsuccessful program indefinitely, because it would provide ENO with no incentive to design the program well or negotiate for reasonably priced RECs, etc.[632] Therefore, the Advisors recommend that the Council require that, in the instance where there are not enough customers participating in the Green Power Option to bear the costs of the program fully, ENO should be allowed to recover costs from non-participating ratepayers, but only after submitting such costs to the Council for review and demonstrating to the Council's satisfaction that the costs were prudently incurred, along with a request to either terminate or alter the program.[633] The Advisors argue that this solution would uphold the requirements of *Hope* and *Bluefield*, while preserving the Council's ability to protect ratepayers from having to bear imprudently incurred expenses and providing ENO with an incentive to run the program well;[634] and

WHEREAS, having considered the arguments of the parties, and considering that Council Docket No. UD-19-01 is ongoing and is actively considering both what resources should be defined as "renewable resources" under the Council's rules and regulations and what certifications

[630] *Id.*, citing City Council Hearing Transcript, 118:22-23 (June 19, 2019).
[631] Advisors' Reply Brief at 55-56.
[632] *Id.* at 56.
[633] *Id.*
[634] *Id.*

would be required for RECs from such resources, the Council finds that ENO's Green Pricing Proposal should be approved with the following modifications:

- to the extent that the Council establishes a definition of "renewable resources" in Docket No. UD-19-01, RECs used for the Green Power Option must originate from sources meeting that definition;

- to the extent the Council adopts a requirement in Docket No. UD-19-01 that RECs be certified and/or tracked through a particular program(s), such as Green-e, then RECs used for the Green Power Option must be certified and/or tracked in the same manner, however, if the Council does not establish such a requirement in Docket No. UD-19-01, then RECs shall be certified through Green-e (or such other certification as the Council may approve in the future); and

- ENO's pricing proposal is approved but shall be modified to clarify that in the instance where there are not enough customers participating in the Green Power Option that the participating customers could reasonably be expected to bear the full costs of the program under the approved pricing structure, ENO should be allowed to recover remaining costs from non-participating ratepayers after submitting such costs to the Council for review and demonstrating to the Council's satisfaction that the costs were prudently incurred, along with a request for Council authorization to either alter the program to ensure that there is reasonable assurance that costs of the program will be paid by participating customers going forward, or a request to terminate the program; and

WHEREAS, the Council agrees with the Advisors' suggestion that to the extent that there is not a final Council decision in Docket No. UD-19-01 prior to the implementation of the Green Power Option, ENO be allowed to utilize any Green-e certified RECs until such time as the Council renders a decision in Docket No. UD-19-01, at which point, ENO must conform its use of RECs to the Council's definition of renewable resources and certification and/or tracking requirements on a going-forward basis; and

COMMUNITY SOLAR

WHEREAS, ENO and BSI both propose some form of community solar program or pricing in this case. ENO proposes its Community Solar Offering ("Schedule CSO") while BSI proposes its CLEP community solar rate; and

(1) *ENO Proposal*

WHEREAS, ENO proposes a new community solar offering whereby participants voluntarily pay for a specific allocation of offsite solar PV projects, and in return for an upfront or ongoing payment, the participant receives a credit on his or her monthly electric bill, tied to the actual output of the solar PV project.[635] ENO proposes to use both its existing ~1 MW_{AC} solar project located at the Paterson site along with the recently approved 5 MW_{AC} rooftop solar project.[636] ENO argues that using existing projects allows interested customers to sign up for a program based on real-life systems as opposed to having to wait until enough interest has been expressed before ENO can move forward with constructing a resource to support community solar;[637] and

WHEREAS, ENO's proposed program would be open to both residential and non-residential customers on non-lighting rate schedules, subject to a few limitations.[638] ENO has designed its proposal as a "pay-as-you-go" model to maximize participation.[639] The monthly charge ENO proposes would be fixed for the duration of the offering and is set at $15.00 per kW_{AC} based on the customer's allocated share in kW.[640] ENO designed this rate to cover the incremental costs associated with using an outside vendor to get ENO's community solar offering up and running, as well as the monthly bill credits that customers receive for participating; it is not meant to cover the upfront and ongoing costs of the solar assets that underpin the offering - those costs will be reflected in overall rates that all customers pay.[641] ENO proposes that the credit rate that is applied to the customer's allocated share of the actual output of the solar systems

[635] Ex. No. ENO-55 at 39.
[636] Ex. No. ENO-10 at 41:16-18.
[637] *Id.* at 41:20-42:3.
[638] *Id.* at 42:15-17.
[639] Ex. No. ENO-55 at 39; Ex. No. ENO-10 at 43:19-20.
[640] Ex. No. ENO-55 at 39; Ex. No. ENO-10 at 44:1-3.
[641] Ex. No. ENO-10 at 44:10-22.

that underpin the community solar offering be based on two components: the historic embedded value of generation, which is adjusted from time to time, and the current FAC value.[642] ENO states that any verified RECs produced by the solar systems that underpin the offering would belong to ENO, would be retired each year, and would not be transferred in any manner to subscribing customers;[643] and

WHEREAS, the Advisors argue that one of the principles established by the Council with regards to community solar programs was the principle of a level playing field.[644] In Resolution No. R-18-223, the Council specifically indicated that:

> In order to ensure a level playing field, to the extent that ENO chooses to become a community solar developer, it must offer the same privileges it allows itself to all other developers. ENO may not give itself preferential treatment as a developer of a community solar project and may not use ratepayer funding for its community solar projects in any manner not available to other developers;[645] and

WHEREAS, the Advisors argue that ENO's proposed Community Solar Offering may result in preferential treatment for ENO that may discourage other Community Solar developers from developing projects in New Orleans under the Council's Community Solar Rules, because, it is ensured to recover its prudently incurred costs of any solar projects, regardless of the number of subscribers its Community Solar Offering has, or whether the fees and credits for its participants fully offset the costs of the projects;[646] and

WHEREAS, this guarantee that ENO would fully recover their costs even if it is not able to attract a sufficient number of subscribers or charge a high enough price, the Advisors argue, is an advantage that other community solar developers will not have.[647] The Advisors express doubt

[642] Ex. No. ENO-55 at 39; Ex. No. ENO-10 at 45:3-8.
[643] Ex. No. ENO-10 at 49:11-13.
[644] Advisors' Initial Brief at 129.
[645] Resolution No. R-18-233 at 3.
[646] Advisors' Initial Brief at 129, citing Ex. No. ADV-1 at 44:12-15 and 44:16-20.
[647] *Id.*

that that approving ENO's Community Solar Offering could bring community solar to New Orleans faster than allowing the market to form naturally under the Council's Community Solar Rules, and argue that it may permanently impair the market by preventing competing developers from being able to compete with ENO;[648] and

WHEREAS, the Advisors also argue that ENO's proposed Community Solar Offering monthly charge is designed to recover only the incremental administrative and marketing costs and the cost of providing solar credits to all potential participants at the retail rate, while the Community Solar Rules clearly state that the capital and operating costs of a community solar garden facility will not be recovered from ratepayers, but rather those costs are the responsibility of the developer/owner of the community solar garden to be recovered from the participants in it.[649] The Advisors argue that ENO's proposal violates this, by requiring ENO ratepayers to pay for a portion of the facilities' fixed costs;[650] and

WHEREAS, in addition, the Advisors argue that ENO's proposed credit for community solar is valued differently than the credit in the Council's Community Solar Rules, and that it would be preferable to have only one methodology for determining the appropriate credit for community solar offerings;[651] and

WHEREAS, ENO acknowledges that its proposed Community Solar Offering Rider does not comply with the Council's Community Solar Rules, but argues that it has sought approval despite those variances and demonstrated with undisputed evidence why Rider CSO can bring greater benefits to customers than if it were modified to conform to the Council's Rules;[652] and

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648 *Id.*
649 *Id.*, citing Ex. No. ADV-3 at 72:4-6 and 72:17-73:1.
650 *Id.*, citing Ex. No. ADV-3 at 73:1-9.
651 *Id.*, citing Ex. No. ADV-1 at 45:2-9 and 45:9-10.
652 ENO Initial Brief at 168.

WHEREAS, ENO also argues that it has attempted to justify its Community Solar Offering in this proceeding and that ENO is entitled to an adjudication on the merits of its proposal in this proceeding based on any regulatory requirements that existed at the time the proposal was filed.[653] ENO argues that customers who enroll in its program would be able to switch to other developers later without any penalties if the Council's community solar initiative ultimately attracts any, and would allow ENO to gain experience with the administration of a community solar offering before the Council's initiative gets under way.[654] ENO also argues that it may reduce the incremental costs of administering the Council's program, thus benefitting those customers as well.[655] ENO argues that its proposal will bring greater benefits than the Council's Community Solar Rules because (1) it will not require the Council or CURO to create additional regulatory mechanisms for the oversight of ENO's proposed rider; (2) it provides the opportunity for customers to participate in "Utility-Scale" offerings that could help to offset the revenue requirements associated with ENO's commitment to add up to 100 MW of renewable energy to its generation portfolio; (3) it would mean that customers have a community solar option in a more timely manner.[656] ENO argues that it would be counterproductive and wasteful for the Council to reject ENO's proposal;[657] and

WHEREAS, ENO argues that the evidence about the potential benefits of ENO's proposed CSO is undisputed and that the Advisors' criticisms and recommendations lack any foundation in evidence submitted in this proceeding.[658] ENO argues that its proposal can be viewed as complementary to, but deliberately designed to be separate from, the Council's

[653] Ex. No. ENO-12 at 39:6-9; Ex. No. ENO-13 at 12:12-13:18.
[654] Ex. No. ENO-12 at 39:16-22.
[655] *Id.* at 39:22-40:3.
[656] *Id.* at 41:9-42:8.
[657] *Id.* at 44:12-13.
[658] ENO Initial Brief at 166-167.

program.[659] ENO also argues that its proposal has the potential to be available much sooner than any offerings developed through the Council's framework;[660] and

WHEREAS, the Advisors argue that ENO misrepresents the Advisors' primary concern.[661] The Advisors argue that the Council must still review ENO's proposal and make sure it is just and reasonable and while compliance with the Council's Community Solar Rules would create a presumption that it is just and reasonable, the fact that formal community solar rules were not in place prior to ENO's proposal does not mean that the Council is obligated to accept whatever community solar project ENO proposes;[662] and

WHEREAS, the Advisors do not believe that the potential near-term benefits of having some form of community solar available to ratepayers more quickly and allowing ENO to gain some experience administering a community solar program will be significant enough to offset the potential damage to the long-term market;[663] and

WHEREAS, AAE and the Sierra Club argue that the Council should reject ENO's specific community solar tariff because the Company failed to establish that the proposal would bring greater benefits.[664] They argue that both of the benefits ENO claims its proposed structure would bring — being able to be in service more quickly and being able to offer it on a "pay-as-you-go" basis without long-term commitments — stem from ENO's status as a regulated utility, and its ability to provide the offering from solar projects that are fully supported by all ratepayers in ENO's rates.[665] They argue that this advantage places other solar developers at a clear and substantial disadvantage and, as a result, such developers may choose not to participate in the

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[659] *Id.* at 167.
[660] *Id.*
[661] Advisors' Reply Brief at 56.
[662] *Id.* at 56-57.
[663] Ex. No. ADV-5 at 37:11-19.
[664] AAE/Sierra Club Initial Brief at 49.
[665] *Id.* at 49-51.

New Orleans market.[666] Thus, AAE and Sierra Club argue, ENO's community solar offering does not meet the standard established by the Council in Resolution No. R-19-11 of demonstrating that the offering provides greater benefits than would a proposal conforming to the Council's recently adopted Community Solar Rules.[667] To the contrary, they argue, ENO's proposal creates the risk of real harm to the nascent community solar market without presenting any real benefits to New Orleans ratepayers, and should therefore be rejected;[668] and

WHEREAS, ENO claims that the Advisors' recommendation expresses a general concern[669] that is unsubstantiated by any analyses, however, the Advisors argue that with significant concerns having been raised by the Advisors, AAE and Sierra Club, ENO bears the burden of demonstrating that its proposal is just and reasonable.[670] Had the proposal been in conformance with the Community Solar Rules, the Advisors argue, a presumption of reasonableness would have been in place, but it is not in conformance, and the Advisors do not believe that ENO has demonstrated that the benefits it claims from bringing community solar to New Orleans faster and allowing a "pay-as-you-go" model (which others may or may not also be able to offer) would outweigh the damage caused to the development of a competitive market for community solar in New Orleans;[671] and

WHEREAS, the Advisors argue that ENO has not made its case in this proceeding that its proposed community solar program is just and reasonable or in the public interest.[672] Nevertheless, the Advisors recommend that the Council reject ENO's proposal in this proceeding without prejudice to ENO and being permitted to re-file either the same proposal or a modified

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[666] *Id.* at 51.
[667] *Id.*
[668] *Id.*
[669] ENO Initial Brief at 167.
[670] Advisors' Reply Brief at 59.
[671] *Id.*
[672] *Id.*

proposal in the Community Solar docket with more support as to the issue of whether ENO's proposed structure would bring greater benefits than would a proposal that conforms to the Council's Community Solar Rules.[673] While ENO argues that requiring an additional filing would create "administrative waste,"[674] the Advisors disagree, writing that the Council needs more information to consider the potential benefits and adverse impacts of ENO's proposal, apart from the focus of the ratemaking decisions of the instant docket;[675] and

WHEREAS, ENO argues that the Advisors' and AAE's concerns about the potential market effect of ENO's Community Solar Offering are exaggerated.[676] ENO argues that AAE had not previously filed any testimony or otherwise previously taken a position on Community Solar.[677] ENO states that the concerns on the impact on the market are exaggerated because its Community Solar offering is limited to 6 MW of solar capacity and that any future community solar offerings made by the Company would be in accordance with the Council's new rules that were implemented after ENO made this rate case filing;[678] and

WHEREAS, the Council is pleased that ENO has been developing a community solar offering for its customers and encourages ENO to continue developing interesting new offerings for its customers; and

WHEREAS, the Council shares the Advisors' concerns that an improperly structured community solar offering could impede the development of a local community solar market; and

WHEREAS, the Council rejects ENO's Community Solar Offering as proposed in this case, without prejudice to ENO proposing a revised Community Solar Offering in the future; and

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673 *Id.* at 59-60.
674 ENO Initial Brief at 167.
675 Advisors' Reply Brief at 60.
676 ENO Reply Brief at 101.
677 *Id.*
678 *Id.* at 101-102.

(2) *BSI Community Solar Proposal*

WHEREAS, BSI proposes a CLEP solar rate where the customer would receive the sum of the monthly kWh produced by the customer's share of the community solar project multiplied by ENO's cost of energy plus the customer's CLEPm payment or charge plus the monthly sum of the customer's CLEP5 payments and charges;[679] and

WHEREAS, the Advisors observe that this would be instead of the community solar payments set by the Council's Community Solar Rules.[680] However, the Advisors argue, while BSI admits that its proposal would not be consistent with the Council's Community Solar Rules, BSI fails to demonstrate to the Council why its Community Solar proposal would provide greater benefits than a proposal that complies with the Council's rules.[681] In addition, the Advisors argue, the CLEP community solar proposal is too complex to be easily understood or implemented by customers;[682] and

WHEREAS, in adopting its Community Solar Rules, the Council explicitly left open the opportunity for parties to propose community solar projects that do not directly conform to the Council's rules and set forth a requirement that parties proposing such a program demonstrate why the alternative proposal brings greater benefits than a proposal conforming to the Community Solar Rules would bring.[683] However, the Advisors argue that BSI has not demonstrated that its community solar proposals provide greater benefit to ratepayers than a community solar project structured under the Council would.[684] Therefore, the Advisors do not recommend that the Council implement CLEP community solar;[685] and

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[679] Ex. No. BSI-1 at 17:16.
[680] Advisors' Initial Brief at 130, citing Ex. No. BSI-1 at 18:3-6.
[681] *Id.* at 130.
[682] *Id.* at 130-131.
[683] *See* Resolution No. R-18-538 at 30-31.
[684] Advisors' Initial Brief at 131.
[685] *Id.*

WHEREAS, while BSI argues that its CLEP proposal generally meets several Council objectives, it provides little description of how the CLEP Community Solar proposal would provide greater benefits to ratepayers than a program designed consistently with the Council's Community Solar Rules, other than that CLEP payments would exceed payments to community solar participants under the Council's Community Solar rules;[686] and

WHEREAS, BSI explains in Appendix 1 of its Reply Brief that it estimates that the CLEP Community Solar price would pay 17% more to participating customers than the retail cost of electricity.[687] BSI also notes in its Initial Brief that CLEP is helpful to community solar by paying 10% higher than retail.[688] However, BSI fails to explain why requiring ENO to pay community solar participants far more per kWh for the electricity they produce than ENO pays for the power it already provides ratepayers will bring more benefits to New Orleans ratepayers than the Council's Community Solar Rules, which endeavor to balance the interests of participating and non-participating customers; and

WHEREAS, BSI argues that CLEP is superior to the Council's Community Solar Rules adopted in Resolution No. R-19-111 because those rules assume that the primary way community solar will be implemented is through utility ownership, but treating Community Solar Farms as private enterprises moots most of the issues addressed in Resolution No. R-19-111.[689] However, the characterization of Resolution No. R-19-111 demonstrates a complete misunderstanding of that Resolution. Resolution No. R-19-111 and the Community Solar Rules adopted therein clearly

[686] Building Science Innovators, LLC Reply Brief at 19, Aug. 9, 2019 ("BSI Reply Brief").
[687] *Id.* at Appendix 1.
[688] *Id.* at 5.
[689] BSI Initial Brief at 24-25.

contemplates that a Community Solar facility could be owned either by the utility or by any other for-profit or not-for-profit entity or organization;[690] and

WHEREAS, in light of BSI's apparent misunderstanding of the Community Solar Rules, the Council gives no weight to BSI's arguments as to how CLEP benefits exceed those of the Community Solar Rules; and

COST RECOVERY FOR THE ENERGY SMART PROGRAM EECR/DSMCR

WHEREAS, as the Advisors explain, the Council has long recognized energy efficiency and demand response offerings (collectively "demand-side management" or "DSM") as high-priority resources for serving ENO's customers, and in 2009, established the Energy Smart program to encourage the development of such resources in New Orleans by offering various programs and incentives for customers wishing to implement DSM measures to reduce their energy use;[691] and

WHEREAS, the Energy Smart Program is now nearing the end of Program Year 9, and has been funded through a variety of mechanisms over the first nine years of its existence.[692] The program has been highly successful, having received the U.S. Environmental Protection Agency's Partner of the Year Award in both 2014 and 2016, a Pro 3 award from the Southeast Energy Efficiency Alliance and a first-in-the-nation ranking in an American Council for an Energy-Efficient Economy study with respect to the kWh savings per participant for low-income customers.[693] The program, however, has lacked a stable and predictable funding source;[694] and

[690] Resolution No. R-19-111, Appendix A at II, Definition of Community Solar Generating Facility.
[691] *See* Resolution No. R-09-136. *See also*, Resolution Nos. R-07-600 and R-09-483; Advisors' Initial Brief at 67.
[692] Advisors' Initial Brief at 67.
[693] Ex. No. ENO-10 at 9:18-24, citing http://aceee.org/sites/default/files/low-income-baseline-0717.pdf.
[694] *Id.* at 11:1-3.

WHEREAS, in this case ENO proposes a new model for cost recovery related to DSM initiatives offered through Energy Smart.[695] ENO's model would use a rider for Energy Smart funding, incorporating a regulatory asset that would earn a return and be amortized over three years, to recover the costs of each Program Year ("PY") of Energy Smart.[696] Under ENO's proposal the return and ROR that ENO would earn on the regulatory asset would function as an incentive mechanism for achieving the savings goals established during the Integrated Resource Plan ("IRP") process.[697] The rider would also recover the LCFC, but would not include those dollars as part of the regulatory asset.[698] ENO argues that its proposed model would fulfill the Council's directive that demand-side resources should be on an equal financial footing with traditional supply-side resources;[699] and

WHEREAS, ENO argues that cost recovery for DSM offerings must fairly address (1) direct and indirect costs of DSM offerings;[700] (2) LCFC and (3) some form of incentive, and that these three elements will "level the playing field" between DSM and supply-side alternatives and will increase the likelihood that a utility will maximize the utilization of cost-effective DSM to meet customer needs;[701] and

WHEREAS, ENO is proposing implementation of two separate riders as funding mechanisms -- one to continue funding for Energy Smart through the end of PY 9, the Interim Energy Efficiency Cost Recovery Rider ("Interim EECR"), and another mechanism intended to be

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695 *Id.* at 3:10-12.
696 *Id.* at 3:12-17.
697 *Id.* at 3:17-21l; ENO Initial Post-Hearing Brief at 111.
698 Ex. No. ENO-10 at 3:20-4:1; ENO Initial Post-Hearing Brief at 111.
699 Ex. No. ENO-10 at 5:8-11.
700 Such costs would include direct incentives paid to customers and other direct costs, ENO labor costs and indirect costs necessary to develop and administer the DSM offerings and provide reporting, and amount paid to ENO's vendors for development and administration of DSM offerings as well as separate EM&V services. *Id.* at 21:9-15.
701 Ex. No. ENO-10 at 18:11-18; *see also* Ex. No. ENO-55 at 33.

applied for PY10 and beyond, the Demand-Side Management Cost Recovery Rider ("Rider DSMCR");[702] and

INTERIM ENERGY EFFICIENCY COST RECOVERY RIDER

WHEREAS, ENO designed the Interim EECR to contemporaneously recover the Council-approved funding for Energy Smart from customers for the period of August 2019 until December 2019[703] (the period between when the new rates go into effect and the end of PY9). ENO proposes that it would serve as an interim universal funding mechanism for both the Legacy ENO and Algiers Energy Smart offerings approved in Resolution No. R-17-623.[704] ENO states that the Council approved a similar Interim EECR in Resolution No. R-17-623 that was never implemented due to the availability of funding from another source[705] and that ENO's proposed Interim EECR Rider in this proceeding utilizes the allocation factors that the Council approved in Resolution No. R-17-623.[706] ENO does not propose to implement the Interim EECR Rider as a line item on customers' bills;[707] and

WHEREAS, the Advisors support the use of the Interim EECR,[708] and no party opposes the Interim EECR; and

WHEREAS, the Council finds the use of the Interim EECR to be reasonable; and

DSM COST RECOVERY RIDER

WHEREAS, the second mechanism ENO proposes for recovery of its costs associated with DSM, its Rider DSMCR, is for PY 10 and beyond.[709] ENO proposes Rider DSMCR in

[702] Ex. No. ENO-10 at 14:3-5; ENO Initial Brief at 112.
[703] Ex. No. ENO-10 at 14:17-19.
[704] *Id.* at 14:10-12.
[705] Resolution Nos. R-17-623 and R-18-227.
[706] Ex. No. ENO-10 at 15:1-2.
[707] *Id.* at 15:5-7.
[708] Ex. No. ADV-3 at 9:11-13, 68:3-13.
[709] Ex. No. ENO-10 at 15:11-14.

response to the Council Resolutions aimed at identifying a permanent funding mechanism for DSM customer offerings (Resolution Nos. R-17-504, R-17-623, and R-17 176).[710] ENO argues that running DSM costs through a rider allows the Council, its Advisors, and other stakeholders to specifically identify and track the level of ENO's investments in DSM and the recovery of those investments and that the use of a rider provides greater stability and facilitates planning by providing a long-term mechanism for helping to ensure that funding will be available, and a rider was clearly identified in Resolution No. R-17-623 as the preferable long-term approach.[711] ENO also argues that use of a rider that is updated annually provides a clearer path for the Council to incorporate changes to Energy Smart, or add other DSM offerings to ENO's demand-side portfolio, which would allow for greater flexibility in responding to customer needs.[712] ENO is not proposing that the rider appear on the customer's bill, rather that it be included within another line item such as the Energy Charge.[713] ENO's proposed Rider DSMCR would have four components;[714] and

WHEREAS, the first component would be the total balance associated with the DSM investment.[715] ENO's Rider DSMCR would utilize regulatory asset-based cost recovery model to allow DSM investment to be treated more equivalently to traditional supply-side and other investments in capital assets.[716] ENO argues this treatment would also initially help mitigate higher bill impacts that would otherwise occur with full contemporaneous cost recovery.[717] ENO proposes to amortize its total DSM investments over a three-year amortization period;[718] and

[710] Ex. No. ENO-55 at 33.
[711] Ex. No. ENO-10 at 16:21-17:11, *see also* Ex. No. ENO-55 at 33.
[712] *Id.* at 17:11-15.
[713] Ex. No. ENO-10 at 17:19-21.
[714] *Id.* at 19:16-18.
[715] *Id.* at 19:11-12.
[716] *Id.* at 19:4-6 and 23:13-15; Ex. No. ENO-14 at 24:17-23.
[717] Ex. No. ENO-10 at 19:6-8; Ex. No. ENO-14 at 25:1-4.
[718] Ex. No. ENO-10 at 22:6-18; ENO Initial Brief at 111.

WHEREAS, AAE opposes the Rider DSMCR rate design. AAE urges the Council to reject ENO's proposal to effectively "rate base" DSM expenses.[719] AAE also argues that the percentage of bill-based design effectively increases the fixed charge that a customer pays each month, which dampens the energy conservation price signal.[720] Additionally, AAE argues it is inappropriate because the objective of avoiding future energy supply costs and potentially distribution infrastructure costs does not have a customer-specific component or any other relationship to costs associated with connecting a customer to the grid.[721] AAE argues that a volumetric charge should be used for Rider DSMCR.[722] AAE recommends the following modifications to the Rider DSMCR: (1) a meaningful minimum savings threshold below which ENO recovers expenses but receives no return on those expenses and is subject to a penalty equivalent to the value of foregone cost savings for failing to achieve the minimum threshold; (2) a more granular formulaic incentive calculation system in place of the large "steps" in ENO's proposal; and (3) a cap on total incentive awards;[723] and

WHEREAS, in response to AAE's argument that the Council should reject any DSM cost recovery that allows ENO to "rate base" DSM, ENO argues that this ignores the Council's goals of aligning the incentives equally for DSM and supply-side resources and providing a comparable earnings opportunity;[724] and

WHEREAS, ENO argues that in order to level the playing field between supply-side and demand-side investments, incentive mechanisms should seek to approximate what the utility would have earned by investing the same amount of capital in a traditional asset;[725] and

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[719] AAE/Sierra Club Initial Brief at 32.
[720] Ex No. AAE-3 at 53:19-54:1.
[721] *Id.* at 53:1-5.
[722] *Id.* at 54:19-20.
[723] Ex. No. AAE-5 at 14:18-15:5.
[724] ENO Reply Brief at 78.
[725] *Id.* at 80.

WHEREAS, the Advisors believe it would be reasonable to use the proposed EECR Rider as the permanent mechanism to recover the costs (which have all been expenses and not capital investment) of the Energy Smart program for both Legacy ENO customers and Algiers customers, and that the Rider DSMCR should not be implemented.[726] The Advisors also recommend that prospective Energy Smart costs beyond 2019 be included in each FRP evaluation;[727] and

WHEREAS, AAE and Sierra Club support the Advisors' proposal to reject the proposed DSMCR Rider and make Interim EECR Rider proposed by ENO the permanent cost recovery method, and they propose removing language referencing LCFC from the EECR Rider and instead addressing the LCFC with the Advisors' proposal to allow for pro forma adjustments to evaluation period filling determinants for the twelve months subsequent to the FRP evaluation period;[728] and

WHEREAS, while ENO argues that Rider DSMCR would initially have a lower impact on customers, the Advisors argue that customers will pay less in total costs by recovering Energy Smart costs contemporaneously as expenses, rather than by deferring expenses and treating them as a regulatory asset.[729] Moreover, the Advisors argue, ENO is not proposing a true regulatory asset treatment, because ENO makes no attempt to match the term of the deferral of the payment of costs to the life of the DSM measures being funded, which is typically more in the 10-20 year range than in the three-year range.[730] Thus, the Advisors conclude, Rider DSMCR does not propose a true leveling of the playing field between DSM and traditional supply-side assets;[731] and

WHEREAS, the Advisors also argue that regulatory asset treatment is appropriate if a large, non-recurring cost is recovered over several future years, whereas Energy Smart costs recur

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726 Ex. No. ADV-3 at 68:7-13; Advisors' Initial Brief at 71.
727 Ex. No. ADV-3 at 68:10-11; Advisors' Initial Brief at 71.
728 AAE/Sierra Club Reply Brief at 11-12.
729 Ex. No. ADV-3 at 69:4-7; Advisors' Initial Brief at 71-72.
730 Advisors' Initial Brief at 72.
731 *Id.*

every year, and are only likely to increase as the program pursues the Council's goal of increasing savings until it reaches 2% of annual sales.[732] The Advisors note that ENO witness Dr. Faruqui argues that while it is true DSM costs would not typically be recovered as a regulatory asset, the traditional regulatory paradigm can act as a road block to encouraging aggressive and effective DSM, and ENO has proposed a progressive solution to encourage innovation.[733] The Advisors, however, are not persuaded that a "progressive solution" that requires ratepayers to pay more in nominal dollars than they otherwise would for DSM in order to allow the utility to earn a return on DSM investment (as deferred expenses) is a solution that benefits ratepayers in the long term;[734] and

WHEREAS, the Advisors argue that while ENO performed and presented an analysis comparing net present values of funding options to demonstrate that ratepayers will ultimately save money with the proposed DSMCR Rider,[735] ENO's Net Present Value calculations hinge on ENO's assumptions regarding the time value of money -- essentially how much benefit a customer receives by being able to make use of their money over the time period for which payment is deferred.[736] The Advisors explain that, as ENO's witness Owens conceded at hearing, ENO's calculations of the value customers receive by being able to spread the costs over three years rather than by paying the costs up front are essentially based on the assumption that on average, customers could earn a return on their money of 7.78% over the time that the customer is able to keep the money.[737] The Advisors argue that this is an overly optimistic expectation of what customers, on average, would be able to achieve in the market or other investment vehicles if they

[732] Ex. No. ADV-3 at 68:1-3 and 69:4-10; Advisors' Initial Brief at 72.
[733] Ex. No. ENO-14 at 10:18-11:10; Advisors' Initial Brief at 72.
[734] Advisors' Initial Brief at 72.
[735] Ex. No. ENO-12 at 18:9-22:4.
[736] Advisors' Initial Brief at 72.
[737] *Id.* at 72-73, citing City Council Hearing Transcript, 137:20-138:16 (June 19, 2019). *See also*, Ex. No. ENO-12 at 19:21-23 demonstrating the average cost of capital utilized was 7.78%.

could invest the amounts they defer paying to ENO, and therefore, the Advisors dispute ENO's claim that the analyses demonstrate that Rider DSMCR will actually have less of an effect on customers than Rider EECR;[738] and

WHEREAS, the Advisors argue that regulatory asset treatment is typically approved for non-recurring costs, like the construction of a power plant, while recurring and increasing annual costs, like those associated with the Energy Smart program, are typically treated as expenses and paid as they are incurred.[739] The Advisors point out that ENO concedes that ratepayers would pay substantially more in nominal dollars under the Rider DSMCR than under the EECR Rider, and ENO's net present value analysis attempting to demonstrate that customers are better off in the long term was based on an unreasonable assumption regarding the time value of money;[740] and

WHEREAS, while the Advisors express appreciation for ENO's stated intent to create a level playing field between supply-side and demand-side resources, they argue if ENO truly desired to create a level playing field, it would amortize the costs of each DSM program year over the life of the DSM resource (typically 10-20 years) rather than only for a three-year period;[741] and

WHEREAS, ENO argues that while the EECR arguably meets the goal of providing stable and predictable funding, it falls well short of meeting the Council's other goals.[742] ENO also argues that the EECR lacks a mechanism for recovery of LCFC and a reasonable performance incentive commensurate with the expected investments in Energy Smart.[743] ENO argues that the DSMCR proposal is the best cost recovery method proposed in this case because it provides the

[738] Advisors' Initial Brief at 73.
[739] *Id.* at 81.
[740] *Id.*
[741] *Id.* at 80-81.
[742] ENO Reply Brief at 75.
[743] ENO Initial Brief at 115.

stable and predictable source of funding and it aligns incentives equally for DSM and supply-side resources and provides the opportunity to earn a comparable return;[744] and

WHEREAS, ENO argues that the company proposed a three-year amortization period rather than a life-of-measure amortization period because it ties directly to the Council's practice of approving portfolios and budgets for DSM programs in three-year cycles as part of the IRP process.[745] ENO notes, however, in its Reply Brief that it would be willing to extend the amortization period to up to 10 years, and that this would still result in Rider DSMCR having a lower rate impact on an NPV basis than the Advisors' proposed EECR;[746] and

WHEREAS, ENO argues that the Advisors' argument that 7.78% is an overly optimistic assumption of what the average ratepayer could earn in the market if they were able to keep and invest the money over the amortization period is unsupported speculation and that the 7.78% is the same discount rate ENO has historically used when comparing resource alternatives and is appropriate if demand-side and supply-side resources are to be evaluated on an equal footing.[747] ENO argues that the Rider DSMCR is the better cost recovery mechanism for pursuing the Council's aggressive DSM goals and implementing its long-term vision, and has a lower rate impact on customers;[748] and

WHEREAS, the Council agrees with the Advisors that DSM expenditures would not typically meet the requirement for being treated as a regulatory asset; and

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[744] ENO Reply Brief at 75.
[745] *Id.*, quoting Ex. No. ENO-10 at 22.
[746] *Id.* at 76.
[747] *Id.* at 77.
[748] *Id.* at 78.

WHEREAS, the Council finds that in light of the concerns raised by the parties, ENO has not presented sufficient evidence of the benefits to customers of its proposal to rate base DSM expenditures; and

WHEREAS, the second component to be recovered through proposed Rider DSMCR would be a utility performance incentive that would involve taking the resulting balance corresponding to the total amount of the investment (as deferred expense) in DSM offerings for a given PY and the Company being allowed to earn a return at ENO's pre-tax WACC based on its allowed ROE, subject to a performance adjustment;[749] and

WHEREAS, AAE argues that it is relatively uncommon for a utility to earn a ROR on DSM expenses, and that rather than being a trend for regulators to grant such treatment, it is merely a trend in what utilities want to get.[750] AAE does support the use of utility performance incentives as a method for encouraging energy efficiency, but states that the Council should be cautious and only reward truly good performance.[751] AAE also prefers an energy efficiency resource standard ("EERS") as a better option than a performance incentive.[752] AAE argues that ENO's proposed performance incentives are too rich and will provide shareholders a return regardless of the amount of savings achieved relative to target;[753] and

WHEREAS, AAE suggests a meaningful minimum savings threshold below which no additional earnings are received, such as 80% of the annual target with penalties for poor performance; a more graduated incentive with more granular steps; and a cap on total incentive awards;[754] and

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[749] Ex. No. ENO-10 at 19:19-23; Ex. No. ENO-14 at 26:12-14.
[750] Ex. No. AAE-3 at 39:14-40:7.
[751] *Id.* at 47:18-48:4.
[752] *Id.* at 48:4-7.
[753] *Id.* at 48:8-19.
[754] *Id.* at 49:15-50:5; AAE/Sierra Club Initial Brief at 40.

WHEREAS, the AAE and Sierra Club also argue that the Council should directly state what performance incentive will be used going forward, and state that they do not object to the performance incentive proposed by the Advisors in the Advisors' March 1, 2018 Energy Smart Plan Recommendations for Program Years 7-9;[755] and

WHEREAS, ENO argues that AAE recommends an unnecessarily punitive performance incentive mechanism that does not recognize the Council's Energy Smart framework already in place.[756] ENO argues that to level the playing field, the incentive mechanism should seek to approximate what the utility would have earned by investing the same amount of capital in a traditional asset.[757] ENO also argues that AAE's proposal to penalize ENO by limiting recovery solely to Energy Smart investments below a predetermined savings threshold, and additionally to impose a second-step penalty equivalent to the value of foregone cost savings for failing to achieve the minimum threshold is unreasonable, absent a finding of imprudence in light of the fact that it is ultimately the Council's decision as to what ENO implements.[758] ENO is, however, amenable to a more granular framework with smaller "steps."[759] In its rejoinder testimony, ENO proposes changing the framework such that achieving between 90% and 110% of targeted Energy Smart savings in a given year would not result in any ROE adjustment while ROE is reduced by 5 basis points for every 1% below 90% that is achieved, and increased by 5 basis points for every 1% above 110% that is achieved, with a maximum of up to 100 basis points.[760] ENO also states that there will be a cap on the performance incentive that is used;[761] and

[755] AAE/Sierra Club Reply Brief at 12, citing Advisors Recommendations for Council Consideration Pursuant to Resolution R-17-623 Re: Unresolved Issues for Energy Smart Program Years 7-9, Docket No. UD-08-02 (Mar. 1, 2018).
[756] ENO Initial Brief at 121.
[757] Ex. No. ENO-12 at 29:11-13.
[758] Ex. No. ENO-13 at 10:2-11.
[759] *Id.* at 10:21-22.
[760] *Id.* at 10:22-11:4.
[761] *Id.* at 33:4:7.

WHEREAS, ENO argues that it makes no sense to defer the incentive mechanism structure, particularly with no guidelines at all around its potential future form, because this would not provide ENO with the certainty necessary to make DSM a core part of its business or put DSM on a level playing field with supply-side resources.[762] ENO urges the Council to determine the appropriate incentive procedure in this docket and not to delay consideration until the Council considers the specific goals and budgets for future years of Energy Smart in the IRP docket;[763] and

WHEREAS, the Advisors argue that while it is appropriate for a utility performance incentive to be included in ENO's compensation for the Energy Smart program, it is more appropriate for such mechanisms to be determined along with the Energy Smart program designs, budgets and savings goals than in a rate case, and the Advisors continue to recommend that the performance incentive be addressed in that proceeding rather than in this case.[764] The Advisors argue that ENO's argument that the Council should determine the appropriate utility incentive procedure in this Docket and not delay consideration is without merit, since the Council will be considering the implementation plan for the next Energy Smart program years in the third quarter of this year;[765] and

WHEREAS, the Council agrees that the appropriate performance incentive for the Energy Smart program is best considered in the Energy Smart docket alongside the targets and budgets set for the program; and

WHEREAS, in light of the anticipated timing of the Council's consideration of the Energy Smart docket, the Council finds that uncertainty regarding the performance incentive is unlikely to exist for an unreasonably long period of time; and

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[762] ENO Initial Brief at 117.
[763] Ex. No. ENO-12 at 23:6-9.
[764] Advisors' Initial Brief at 82.
[765] *Id.*

WHEREAS, the third component to be recovered through Rider DSMCR would be LCFC, adjusted each year based on the incremental (or decremental) change to ENO's DSM investment and resulting projected energy savings.[766] ENO proposes to calculate projected annualized LCFC amounts the same way that LCFC has been calculated historically, albeit with updated values reflecting the outcome of the rate case.[767] ENO proposes to calculate the total projected annualized LCFC amount for the upcoming year, which would be recovered concurrently through the Rider DSMCR (but not through the regulatory asset) and would be subject to a true-up relative to actual results that would occur in the following year.[768] ENO argues that it is important to provide recovery of LCFC in order to put DSM offerings and more traditional, supply-side resources on more equal footing;[769] and

WHEREAS, AAE opposes ENO's proposal to collect LCFC, and argues that a utility that has a decoupling mechanism will automatically recover the net effect of any energy or demand reduction resulting from its program, along with changes in energy and demand resulting from matters outside its influence or control, and therefore ENO does not need LCFC.[770] AAE also argues that an LCFC is not necessary to level the playing field between demand-side and supply-side resources because demand-side resources are more appealing than supply side resources due to the lack of any need for the utility to have any ongoing role in maintenance or operation of those resources.[771] AAE recommends that the Council reject the LCFC in favor of a simple decoupling mechanism that AAE proposes[772] and arguing that a full decoupling mechanism is a superior

[766] Ex. No. ENO-10 at 20:1-6.
[767] *Id.* at 28:3-5.
[768] *Id.* at 28:8-12; Ex. No. ENO-14 at 25:11-18.
[769] *Id.* at 28:18-20.
[770] Ex. No. AAE-1 at 30:21-31:4; AAE/Sierra Club Initial Brief at 33.
[771] Ex. No. AAE-1 at 33:6-34:21.
[772] *Id.* at 38:16-17.

mechanism to a lost revenue adjustment.[773] AAE and Sierra Club also point out that ENO has failed to explain several aspects of its LCFC proposal, including the definition of adjusted gross margin and how reconciliation will occur;[774] and

WHEREAS, AAE also points out that lost revenues are not themselves equivalent to under-recovery of fixed costs for the utility because other factors, such as weather, customer growth, economic growth, or off-system sales may provide a balancing effect.[775] AAE also argues that there is strong evidence that decoupling is generally associated with better energy efficiency outcomes than LCFC;[776] and

WHEREAS, the Advisors oppose the inclusion of LCFC in any cost recovery mechanism,[777] noting that ENO's own witness, Dr. Faruqui states:

> To address the issue of LCFC, regulators in many states allow utilities to recover the LCFC that is specifically associated with reduced energy sales due to the utility's DSM investments. Recovery of DSM-specific LCFC is most commonly achieved concurrently through a dedicated DSM rider based on a forward-looking period. In some states, regulators have **instead** chosen to fully decouple the utility's revenues from its energy sales (known as "full revenue decoupling.") (Emphasis Added);[778]

WHEREAS, in Resolution No. R-16-103, the Council directed ENO to file a proposal for full decoupling in this Combined Rate Case.[779] Therefore, the Advisors argue, the inclusion of LCFC in a DSM-specific rider is not appropriate, rather, any erosions in fixed costs should be considered in the annual FRP review and Decoupling mechanism;[780] and

[773] Ex. No. AAE-3 at 39:8-13; AAE/Sierra Club Initial Brief at 34-35.
[774] AAE/Sierra Club Initial Brief at 36-37.
[775] Ex. No. AAE-3 at 42:15-18.
[776] *Id.* at 44:8-46:7.
[777] Ex. No. ADV-3 at 76:5-6.
[778] Ex No. ENO-14 at 12:17-13:2.
[779] Resolution No. R-16-103 at 21.
[780] Ex. No. ADV-3 at 76:6-7; Advisors' Initial Brief at 78.

WHEREAS, Air Products, however, argues that to the extent the Council allows ENO to recover any LCFC costs, those costs should be recovered as part of the EECR or DSMCR mechanism and not as part of the FRP and decoupling mechanisms in order to keep those costs associated with the programs and customers that cause them.[781] Air Products notes that if the Advisors' proposal is to include LCFC in FRP evaluations and decoupling mechanism using the same allocation used by the EECR, it may address Air Products' concern;[782] and

WHEREAS, Air Products also argues that energy efficiency programs increase the utility's average cost of supplying service, resulting in an increase in rates, and that such programs can only be regarded as beneficial to nonparticipants of the end result were to be rates lower than they otherwise would have been, as evidenced by a Ratepayer Impact Measure test of 1.0 or greater.[783] Air Products argues that such an outcome is rare, and there is no evidence to support the RIM test results for the energy efficiency program being in excess of 1.0, therefore nonparticipants do not benefit from the energy efficiency programs;[784] and

WHEREAS, ENO argues Air Products' comments regarding the cost-effectiveness of energy efficiency are misplaced, because the Council has established rules and a process for assessing the cost effectiveness of each PY's portfolio of DSM offerings and their associated budgets;[785] and

WHEREAS, ENO emphasizes that it is undisputed that LCFC needs to be addressed, it is just a matter of where, but agrees with the Advisors that if the final design of the FRP incorporates features that ENO believes adequately address LCFC, then the Company would not need to recover

781 Ex. No. AP-4 at 12:13-13:14; Air Products' Initial Brief at 34; Air Products' Reply Brief at 5.
782 Air Products' Initial Brief at 34.
783 Ex. No. AP-4 at 13:15-21.
784 *Id.* at 14:1-4.
785 Ex. No. ENO-13 at 12:7-9.

LCFC amounts in Rider DSMCR or through some other cost recovery mechanism other than the FRP.[786] ENO witness Owens stated in his rebuttal testimony that the Advisors' proposal to make proforma adjustments to address timely recovery of demand-side management costs could present a workable solution to the LCFC issue, contingent on agreeing on the specific FRP language.[787] ENO does not, however, believe that the AAE's decoupling proposal could adequately address LCFC because it would delay recovery of the lost revenues by at least a year.[788] ENO opposes methods of cost recovery that would cause ENO to be always a year or more behind in the recovery of fixed costs attributable to Energy Smart-related DSM investments;[789] and

WHEREAS, the Council agrees with the Advisors that the erosion of any fixed costs is best considered in the annual FRP review and Decoupling mechanism; and

WHEREAS, finally, the fourth component included in ENO's proposed Rider DSMCR would be an adjustment resulting from a true-up that will occur once a year based on prior year actual results.[790] ENO proposes that Rider DSMCR rates be set only once a year and take effect at the beginning of each PY with the first billing cycle.[791] ENO also argues that the EECR may over or under-recover Energy Smart costs if it does not include some form of annual true-up mechanism within the EECR Rider, because of EECR revenues in any given year were less than the amount of Energy Smart program costs, but the FRP evaluation results were within the bandwidth, no rate adjustment would occur, and ENO would not recover all of the Energy Smart costs for that year;[792] and

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786 Ex. No. ENO-12 at 10:13-18.
787 Ex. No. ENO-13 at 7:10-11; *see also*, ENO Reply Brief at 80.
788 Ex. No. ENO-13 at 7:17-8:5.
789 Ex. No. ENO-12 at 11:4-11 and 12:11-19.
790 Ex. No. ENO-10 at 20:16-18.
791 *Id.* at 20:18-19.
792 Ex. No. ENO-12 at 23:10-17.

WHEREAS, the Advisors recommend that the EECR Rider be utilized as the long-term funding mechanism for the Energy Smart program and argue that ENO has failed to demonstrate that its proposed Rider DSMCR would be more beneficial to ratepayers than the EECR Rider.[793] The Advisors argue that compared to ENO's arguments for its proposed DSMCR, the EECR (i) does represent a permanent funding mechanism, (ii) can track DSM investments and cost recovery through annual filings, (iii) provides stability by ensuring funding will be available, (iv) provides a clear path and flexibility to incorporate changes to DSM, (v) does not have to appear as a separate line item on customers' bills, and (vi) represents less of a financial burden to ratepayers than DSMCR, since the nominal cost to ratepayers with DSMCR would be higher including ENO's return on the regulatory asset;[794] and

WHEREAS, the Advisors assert that the EECR Rider will provide ENO with a reasonable opportunity to recover its DSM investments and[795] that lost revenues due to the Energy Smart program should be addressed through the decoupling and FRP mechanisms, rather than the proposed DSMCR rider.[796] The Advisors argue that the purpose of allowing lost revenue recovery is not to guarantee that the utility earns exactly as much money as it would if DSM was not implemented, rather it is to ensure that the utility has a fair and reasonable opportunity to earn its authorized revenue requirement.[797] Further, the Advisors state, to the extent that increased sales due to weather or other factors offsets revenues lost due to the implementation of energy efficiency measures, there is simply no need to further compensate ENO;[798] and

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[793] Advisors' Initial Brief at 80.
[794] *Id.*
[795] *Id.* at 81.
[796] *Id.*
[797] *Id.*
[798] *Id.*

WHEREAS, the Council finds that the EECR Rider is the appropriate long-term funding mechanism for the Energy Smart program; and

DEMAND RESPONSE MECHANISMS

WHEREAS, both ENO and BSI propose rates that would allow customers to be paid for actively reducing their load during key times; and

(1) *ENO Proposal - Extend MVLMR and MCDRR to All Customers*

WHEREAS, ENO proposes to extend two of the riders previously in effect in the Algiers territory to all of its customers, the Market Valued Load Modifying Rider ("MVLMR") and the Market Valued Demand Response Rider ("MVDRR").[799] ENO explains that these riders provide the opportunity for qualified retail customers, or qualified aggregators of retail customers, to act as a load modifying resource (MVLMR) or a demand response resource (MVDRR), consistent with MISO-prescribed standards and requirements;[800] and

WHEREAS, the Advisors note that demand response and load modifying resources are important facets of the Council's policy to expand demand side management in New Orleans,[801] and because these riders have already been implemented in Algiers, and ENO has experience administering the Riders; the Advisors support ENO's proposal to expand the MVLMR and MVDRR to ENO's full service territory.[802] The Advisors recommend, however, that because many customers will be unable to perform a cost benefit analysis of the investment they make by volunteering in the riders, ENO should provide support, such as providing a cost estimate from the

[799] Ex. No. ENO-55 at 30.
[800] Ex. No. ADV-3 at 64:13-18.
[801] Ex. No. ADV-3 at 64:18-20.
[802] Advisors' Initial Brief at 120-121.

MISO tariff and other related information regarding cost, to customers to help them make more informed decisions as to whether to voluntarily participate;[803] and

WHEREAS, the AAE and Sierra Club also support the extension of the MVLMR and MVCRR riders to its full service territory.[804] They support the suggestion that ENO be required to provide some kind of support to potential participants, including a cost-estimate so potential customers understand the programs and know what they are getting into.[805] AAE and Sierra Club also propose, for the first time in their Reply Brief, that the MVLMR rider be amended to (a) make it a multi-year commitment so that it is a useful planning resource for ENO; (b) increase the compensation towards long-term avoided costs to recognize the fact that it is a useful planning resource, and (c) allow customers to participate through aggregators of retail customers;[806] and

WHEREAS, no party opposes the extension of ENO's MVLMR and MVDRR riders to ENO's full service territory; and

WHEREAS, the Council notes that AAE and Sierra Club's proposed changes are not supported by any evidence in the record and were proposed for the first time in their Reply Brief such that no other party has had opportunity to probe or respond to the proposals; and

WHEREAS, the Council agrees that the expansion of the demand response riders supports the Council's policy to expand demand-side management in New Orleans; and

WHEREAS, the Council finds it reasonable to require ENO to add a component of customer support, including the provision of cost estimates to customers to be reasonable; and

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803 Ex. No. ADV-3 at 65:4-9; Advisors Initial Brief at 121.
804 AAE/Sierra Club Reply Brief at 21-22.
805 AAE/Sierra Club Reply Brief at 22.
806 *Id.* at 22.

(2) *BSI CLEP Proposal*

WHEREAS, BSI proposes the adoption of three Customer Lowered Energy Pricing ("CLEP") rates, a CLEP residential rate, a CLEP non-residential rate, and CLEP community solar.[807] CLEP community solar is discussed above along with ENO's community solar proposal. Under the proposed CLEP rates, a customer either earns a payment or incurs a charge every five minutes (called "CLEP5").[808] The customer earns a CLEP5 payment for each five minute period in which either (a) the customer purchases electricity from ENO when the current MISO price of energy is lower than ENO's cost to produce energy; or (b) the customer sells electricity to ENO when the current MISO price of energy is higher than ENO's cost to produce energy.[809] Conversely, the customer would incur a CLEP5 charge within each five-minute period that the customer either (a) purchases electricity from ENO when the MISO price for electricity is higher than ENO's cost to produce energy or (b) sells electricity to ENO when the current MISO price for energy is lower than the ENO's cost to produce electricity;[810] and

WHEREAS, customers would also earn monthly payments or incur monthly charges (called CLEPm) for providing or demanding power at nearly the same times the utility experiences its annual peak demand.[811] The CLEP5 payments and charges are summed monthly and added to the CLEPm payment or charge to produce a credit or charge on the customer's monthly bill.[812] It does not replace and otherwise has no effect on the customer's regular monthly bill under the

[807] Ex. No. BSI-1 at 6:13-16.
[808] Ex. No. BSI-1 at 12:1-9.
[809] Ex. No. BSI-1 at 12:1-9.
[810] Ex. No. BSI-1 at 12:9-13.
[811] Ex. No. BSI-1 at 12:17-19.
[812] Ex. No. BSI-1 at 16:11 and 17:1.

customer's regular rate.[813] If CLEP results in a payment to the customer that exceeds the charges the customer owes on its monthly bill, the customer receives a monetary credit;[814] and

WHEREAS, BSI states that CLEP payments benefit non-CLEP customers because "Every CLEP transaction will include a 5% service charge to be collected by the utility. Thereafter, some portion of the 5% service charge can be distributed to all ENO customers after deducting ENO's administrative costs according to the Council's rulemaking."[815] BSI also states that appropriate use of the CLEP rate by a customer will lower the average cost of electricity ENO incurs, while a CLEP customer that fails to modify their behavior and makes purchases or sales at the wrong time will only cause an increase in their own electricity bill;[816] and

WHEREAS, BSI argues that its CLEP rate would lower ENO's true cost of service to supply power, enhance reliability, appropriately assign demand charges to customers with higher than usual demand, correctly reflects residential customers' impact on demand and energy use, account for entities with a peak that differs from ENO's peak, provide economic benefit to customers who have heavily invested in storage, provide credits to EV owners who charge off peak, provide a financial incentive to install batteries, and generally cause customers to make choices that will lower demand;[817] and

WHEREAS, the Advisors argue that whether the CLEP proposal will actually produce these benefits is uncertain.[818] In addition, the Advisors find the design of CLEP to be extremely complicated and not one that customers will easily be able to navigate.[819] The Advisors believe customers are unlikely to be able to determine the relative positions of ENO and MISO's costs of

[813] Ex. No. BSI-1 at 14:17-22.
[814] Ex. No. BSI-1 at 15:15-17.
[815] Ex. No. BSI-1 at 22:9-12.
[816] Ex. No. BSI-1 at 22:18-23:4.
[817] Ex. No. BSI-1 at 23:16-26:4.
[818] Advisors' Initial Brief at 122.
[819] Advisors' Initial Brief at 122-123.

producing electricity in five-minute increments.[820] The Advisors point out that BSI is clear that CLEP customers who fail to successfully adapt their behavior to change as the relative positions of ENO and MISO's costs change would see an increase in their electricity bills.[821] ENO opposes the CLEP proposal and argues that it appears to be substantially the same as to the proposal already rejected by the Council in Resolution Nos. R-16-106 and R-17-100.[822] The Advisors believe that the most likely outcome of implementing CLEP would be that most CLEP customers experience difficulty in managing their energy use and production in five minute increments, resulting in increased electricity bills and frustration.[823] Therefore, the Advisors do not recommend that CLEP be adopted by the Council, particularly in light of the demand response opportunities available under Riders MVLMR and MVDRR;[824] and

WHEREAS, the Advisor argue that as BSI notes, there are two primary ways that a customer can benefit from CLEP, the first would be by investing in programmable appliances and programming those appliances to run in a manner that takes advantage of CLEP pricing.[825] The second would be by hiring an aggregator to assist them.[826] The Advisors agree with BSI that, at least initially there will be few, if any, aggregators able to provide such a service,[827] and the Advisors note that it will take an extensive level of expertise in both ENO's pricing structure and MISO markets and will require access to real-time information about the price differentials between the two, in five-minute increments, as well as fairly extensive control over the consumer's

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[820] Advisors' Initial Brief at 122-123.
[821] Advisors' Initial Brief at 123.
[822] Ex. No. ENO-12 at 50:7-11.
[823] Advisors' Initial Brief at 123.
[824] Advisors' Initial Brief at 123.
[825] Advisors' Reply Brief at 60, BSI Initial Brief at 36.
[826] Advisors' Reply Brief at 60, BSI Initial Brief at 36.
[827] Advisors' Reply Brief at 60, BSI Initial Brief at 36.

consumption of electricity in five-minute increments, for an aggregator to effectively help customers make money by participating in CLEP;[828] and

WHEREAS, the Advisors argue that as to the use of programmable appliances, BSI posits that programming them to always run at the same time of day would be sufficient to allow a customer to profit from CLEP, but while this may generally work under average circumstances, it may not be able to shield customers from being penalized under CLEP when there are unexpected developments in the MISO market, such as unanticipated generator outages or capacity shortages.[829] Thus, the Advisors note, there is no guarantee that a customer will only get payments from CLEP and not incur occasional penalties.[830] As BSI notes, the electricity bill of a customer participating in CLEP could either go up, go down, or hardly change.[831] The Advisors note that as homes become increasingly automated over time and the grid becomes modernized and smarter, it is possible that at some point in the future a CLEP-like model could be adopted that allows smart devices and Artificial Intelligence to effectively manage energy use for the customer so that customers can benefit from CLEP with much less effort and investment, and at such time, it may make sense for the Council to consider such a model.[832] However, the Advisors argue, that time has not yet come, as matters stand today, the CLEP model is impractical to implement, and should be rejected by the Council;[833] and

WHEREAS, ENO supports the Advisors' arguments in favor of rejecting the BSI CLEP proposal.[834] ENO also points out that while CLEP participants would be engaging in energy transactions every 5 minutes, the data from AMI meters is recorded and transmitted in 15-minute

[828] Advisors' Reply Brief at 60-61.
[829] Advisors' Reply Brief at 61.
[830] Advisors' Reply Brief at 61.
[831] BSI Initial Brief at 35.
[832] Advisors' Reply Brief at 61.
[833] Advisors' Reply Brief at 61.
[834] ENO Reply Brief at 84-85.

increments, thus, it does not appear that it is possible to implement CLEP without significantly altering the configuration of AMI deployment, which is presently underway;[835] and

WHEREAS, BSI also requests that the Council appoint a Load Flexibility and Time-of-Use Rate-Design Working Group to begin work immediately in designing and implementing CLEP that would include key stakeholders, ENO, the Council's utility Advisors, residential, commercial, municipal, water utility, and industrial customers, environmental justice and conservation communities and nationally recognized experts on load flexibility, and time of use rates, and that the Council should hire an independent consultant to advise the Working Group as well;[836] and

WHEREAS, although BSI argues that CLEP fulfills nearly every regulatory purpose and goal of the Council as well as addressing Global Warming and Sea Level Rise and will lower rates to all customers, the Council finds these claimed benefits to be speculative in nature and the overall design of CLEP to be overly complicated for consumers to understand while requiring a considerable amount of either programmable equipment, or skill and expertise either by the customer or an aggregator to be practical to implement at this time; and

WHEREAS, having rejected the CLEP proposal, the Council also rejects as moot BSI's request for the establishment of a working group to design and implement the CLEP proposal; and

EV CHARGING INFRASTRUCTURE

WHEREAS, ENO proposes two different concepts designed to expand access to EV charging infrastructure in New Orleans and which would complement an offering currently

[835] ENO Reply Brief at 85.
[836] BSI Reply Comments at 8.

available to residential customers.[837] ENO also proposes a separate initiative involving rebates for customer-owned EV charging infrastructure;[838] and

(1) *Rider Schedule Electric Vehicle Charging Infrastructure ("EVCI")*

WHEREAS, the first concept, available to non-residential customers, would involve ENO constructing, owning, and operating EV charging infrastructure on customer-owned property.[839] In return, the customer would pay a fixed amount each month tied to a percentage specified under the proposed Rider Schedule EVCI and the installed cost of the equipment, less (1) the value of a 30% tax credit available from the State of Louisiana and (2) an estimated level of near-term, non-fuel revenue.[840] ENO argues that there are several benefits to non-participating customers: (1) new revenues from charging usage helps recover fixed costs on ENO's system and other costs, and thus helps control rates for all of ENO's customers; (2) only the participating customer is paying for the dedicated EV charging facilities; (3) to the extent the customer uses the program to provide public EV charger access (such as at a shopping mall or parking lot), non-participants who live in New Orleans and own or lease an EV would benefit from increased access; and (4) expanding access to EV charging infrastructure would provide important environmental and other public policy benefits.[841] ENO states that customers who take advantage of this program will be able to provide access to the chargers to their employees, customers, and/or tenants without issue, including being able to charge a fee for use of the charger;[842] and

[837] Ex. No. ENO-55 at 40.
[838] Ex. No. ENO-10 at 58:5-7.
[839] Ex. No. ENO-55 at 40; Ex. No. ENO-10 at 58:8-14.
[840] Ex. No. ENO-55 at 40; Ex. No. ENO-10 at 59:9-12.
[841] Ex. No. ENO-10 at 60:18-61:4.
[842] Ex. No. ENO-10 at 64:19-21.

WHEREAS, the Advisors state that ENO's Rider EVCI proposal is properly constructed.[843] The Advisors find that the rider would be entirely voluntary to ratepayers and would not impose any material costs on non-participant ratepayers.[844] The proposed Rider EVCI is consistent with the theory underlying Rider AFC, which the Council has already approved.[845] There appears to be no reason to expect that Rider EVCI would prevent ratepayers from funding their own EV charging stations; a commitment under Rider EVCI is entirely voluntary; however, the Council may wish to make clear to ENO that similar new meter installations are appropriate for ratepayer-funded EV charging stations, subject to all of ENO's service standards.[846] The Advisors recommend that the Council approve Rider ECVI-1 as proposed by ENO, and specifically note that it is not to be applied prejudicially to ratepayers who choose to construct EV charging stations outside of Rider EVCI in terms of vendor selection, provision of related electric service, and financing services;[847] and

WHEREAS, no party opposes Rider EVCI; and

WHEREAS, the Council finds EVCI to be reasonable; and

(2) Public EV Charging Infrastructure Offering

WHEREAS, ENO's second proposal would be available to public institutions and would involve ENO constructing, owning, and operating EV charging infrastructure solely for public use at a handful of key locations in New Orleans.[848] ENO would collaborate with City officials to determine optimal locations for the EV chargers, which could include downtown City-owned

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843 Advisors' Initial Brief at 135, Ex. No. ADV-6 at 94:10-11.
844 Advisors' Initial Brief at 135, Ex. No. ADV-6 at 94:11-12.
845 Advisors' Initial Brief at 135, Ex. No. ADV-6 at 94:12-14.
846 Advisors' Initial Brief at 135, Ex. No. ADV-6 at 94:19-95:1.
847 Advisors' Initial Brief at 135-136, Ex. No. ADV-6 at 95:19-96:2; Ex. No. ADV-2 at 50:6-8.
848 Ex. No. ENO-55 at 40; Ex. No. ENO-10 at 58:15-15-17.

right-of-way, public libraries and schools, parks, and other recreational areas.[849] ENO is proposing to invest up to $500,000 over the next 24-30 months to build out EV charging infrastructure on public property that would be made accessible to electric vehicle drivers.[850] ENO is proposing to recover the capital investment and related expenses in retail rates through the normal ratemaking process;[851] and

WHEREAS, ENO is proposing that no additional fee or charge be levied on any EV driver for using the charging equipment regardless of where the EV charger is located relative to a customer's meter.[852] ENO explains that the City or other public entity that owns the property may charge for parking, but ENO would not impose an additional fee or charge related to using the EV charger or the electricity dispensed by the equipment used to charge the EV's battery.[853] ENO anticipates that the cost of the electricity provided in this manner would be small, and for locations where the charging equipment is not behind the customer's meter, ENO proposes that the value of electricity not being billed to the EV drivers would be reflected in ENO's FAC in the same way that unaccounted-for energy from line losses and other forms of non-technical losses are treated today;[854] and

WHEREAS, the Advisors support EV charging stations installed behind the ratepayer meter, where the ratepayer pays ENO for the electricity consumed and then makes a decision as to whether and how much to charge users of the EV charging stations to charge their cars.[855] The Advisors support the ability of such ratepayers to offer amenities, such as free EV charging, that

[849] Ex. No. ENO-55 at 40-41; Ex. No. ENO-10 at 58:17-20.
[850] Ex. No. ENO-55 at 41; Ex. No. ENO-10 at 58:22-23.
[851] Ex. No. ENO-55 at 41; Ex. No. ENO-10 at 67:16-19.
[852] Ex. No. ENO-10 at 68:3-5.
[853] Ex. No. ENO-10 at 68:5-8.
[854] Ex. No. ENO-10 at 68:8-15.
[855] Advisors' Initial Brief at 137, Ex. No. ADV-6 at 100:12-15.

the ratepayer deems valuable to their business or purpose, and do not view free EV charging offered in this context as anti-competitive;[856] and

WHEREAS, the Advisors, however, do believe that ENO's proposal to build some charging stations in front of the customer meter (where use is not measured or paid for) and to offer charging for free to EV drivers with the costs rolled into ENO's rates and borne by all ratepayers could be problematic.[857] First, the Advisors argue, the generally accepted regulatory ratemaking principle of cost causation does not support socializing one ratepayer group's (*i.e.*, EV charging station users) costs among other groups (*i.e.*, all other ratepayers), even if the subsidy is small, it is not appropriate to require other ratepayers to pay for an EV charger customer's electricity.[858] Second, free EV charging offers an incentive for EV owners to avoid charging where energy is not free, such as at home.[859] Further, the Advisors express concern that since EV owners reasonably could be expected to prefer free EV charging stations over those that charge a fee, non-ENO EV charging station providers could be deterred from installing EV charging stations near an ENO free EV charging station;[860] and

WHEREAS, the Advisors argue that adding EV charging stations is consistent with the Council's goals and policies regarding Smart Cities and environmental benefits for New Orleans; however, rather than having the Council decide an issue that could have such a significant impact upon the market for EVs in New Orleans as part of this rate case, the Advisors initially recommend that the issue of whether ENO should install EV chargers and/or offer free charging to the public should be taken up in the EV Docket, UD-18-01, where stakeholders with an interest in

[856] Ex. No. ADV-6 at 100:12-15.
[857] Advisors' Initial Brief at 137.
[858] Advisors Initial Brief at 137, Ex. No. ADV-6 at 99:4-7. Advisors' witness Watson calculates the amount to be socialized in this manner as possibly being as high as $64,432, ENO witness Owens argues that it would be only a fraction of that amount. Ex. No. ENO-12 at 46:3-21.
[859] Advisors' Initial Brief at 137, Ex. No. ADV-6 at 99:7-9.
[860] Advisors' Initial Brief at 138, Ex. No. ADV-6 at 100:8-10.

encouraging EVs in New Orleans will have better opportunity to participate in the discussion;[861] and

WHEREAS, with respect to the Advisors' proposal that the issue be considered not in this proceeding, but in UD-18-01, ENO proposes that the issue of ENO's investment be separated from the issue of where to locate the EV chargers, and that Docket UD-18-01 might be the forum in which ENO, the City and the stakeholders could collaborate as to where to locate the estimated 30 to 50 Level 2 chargers that ENO would construct and operate.[862] The Advisors agree with ENO's proposal and recommend that ENO be allowed to proceed with its proposed $500,000 investment with siting of the charging stations to be considered as part of Council Docket No. UD-18-01.[863]

WHEREAS, the Advisors explain that the proposal to authorize ENO to invest up to $500,000 in public EV charging infrastructure in the instant proceeding and then use Council Docket No. UD-18-01 to engage stakeholders where best to cite ENO's proposed EV chargers is reasonable and mitigates the Advisors' concerns, particularly in light of Council's stated interest in promoting environmental benefits, the limited scope of ENO's specific investment proposal, and the minimal amount of socialized costs.[864] The Advisors, therefore, recommend that the Council authorize ENO's proposed investment of up to $500,000 in public EV charging infrastructure that would provide free EV charging services at roughly 30-50 locations and consider any stakeholder input as to the siting of such locations in Council Docket No. UD-18-01;[865] and

[861] Advisors Initial Brief at 138, Ex. No. ADV-6 at 100:16-102:3.
[862] ENO Initial Brief at 181, and Ex. No. ENO-12 at 48:1-11.
[863] Advisors Initial Brief at 138-139, Ex. No. ADV-8 at 51.
[864] Advisors Initial Brief at 139, Ex. No. ADV-8 at 51:9-14.
[865] Advisors Initial Brief at 139, Ex. No. ADV-8 at 51:18-52:3.

WHEREAS, the Council finds the compromise proposed by ENO and the Advisors to be reasonable; and

(3) *Rebate for EV Charger Installation*

WHEREAS, ENO also proposes to continue with its Electric Technology initiative ("eTech") under which it provides a $250 rebate to qualifying customers to partially offset the costs they incur to install Level 2 EV chargers at their home or business.[866] ENO argues that the program is beneficial, because it allows ENO to know which of its customers have installed a Level 2 charger, and to periodically get data about impacts on electric load including hours of the day, possible frequency of charging, and so forth.[867] Knowing where EV chargers are located on its system and being able to perform analysis could help with grid planning and maintain reliability and also help inform how grid modernization can help to accommodate increased penetration of EVs.[868] ENO could also periodically survey participating customers to better understand their real-world experience as EV drivers in New Orleans, what actions they would like to see taken by ENO and/or the City to expand access, etc.;[869] and

WHEREAS, the Advisors also support ENO's proposed EV charger rebate program.[870] A Level 2 charger may be considered a load-modifying resource when used off-peak, which can generate benefits for all ratepayers reflected in MISO charges and credits.[871] Because Level 2 chargers can be viewed as DSM and, when used off-peak, are likely to utilize less carbon-intensive production resources, the Advisors believe that encouraging Level 2 EV chargers through a rebate program is consistent with the Council's policies on energy efficiency and environmental

[866] Ex. No. ENO-10 at 69:9-12.
[867] Ex. No. ENO-10 at 69:16-19.
[868] Ex. No. ENO-10 at 69:19-70:2.
[869] Ex. No. ENO-10 at 70:3-70:6.
[870] Advisors Initial Brief at 140.
[871] Ex. No. ADV-6 at 96:16-97:1.

benefits.[872] The Advisors also believe that because EV chargers may be considered energy efficiency or DSM measures, it would be most appropriate to fund them through the Energy Smart Program, going forward, but recognizing that the earliest such a mechanism would be in place would be for Energy Smart Program Year 2020, the Advisors recommend that in the interim, the Council authorize ENO to continue its $250 per Level 2 charger rebate program, and that any related cost recovery proposal be considered through the FRP mechanism;[873] and

WHEREAS, ENO argues that the eTech efforts are efforts at electrification (conversion of equipment that uses fossil fuel to electric), which ultimately increases electricity usage, and therefore should not be considered energy efficiency measures and funded through the Energy Smart program.[874] ENO argues that the costs should be recovered through normal ratemaking;[875] and

WHEREAS, ENO and the Advisors appear to be in agreement that the eTech program should continue, no party opposes it, and it is consistent with the Council's interest in fostering EV adoption in New Orleans. The Council finds that the eTech program should continue; and

WHEREAS, the Council finds that it may be advantageous to ENO's customers to have the eTech offering conveniently included within the Energy Smart program, and so agrees with the Advisors that the eTech rebate should be part of that program. However, the Council appreciates ENO's concern that the measure could increase a customer's overall energy use, rather than decrease it. To that end, the Council finds that it would be reasonable in the consideration of the design of the Energy Smart Implementation Plan for PY 10-12, for the parties to develop a method of evaluating the success of the eTech program separate and apart from the kWh savings

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[872] Ex. No. ADV-6 at 97:1-4.
[873] Ex. No. ADV-6 at 97:6-98:5.
[874] Ex. No. ENO-12 at 49:3-16.
[875] Ex. No. ENO-12 at 49:16-18.

goals of the other Energy Smart program measures, such that increases energy usage related to the eTech program does not count against ENO's ability to achieve the kWh and any kW savings goals established for Energy Smart PY 10-12; and

SERVICE REGULATION AMENDMENTS

WHEREAS, ENO proposes certain minor modifications to its Service Regulations to reflect current practices, add new definitions, requirements and modifications necessary to reflect the changing nature of service (such as AMI, and the new offerings).[876] ENO states that such minor modifications include changes such as updating listings for ENO's website, updating hours of Customer Service centers, and job titles for certain employees, updating certain definitions to reflect AMI deployment, and language that separately references East Bank and West Bank customers, and eliminating outdated or duplicative language, as well as changes reflecting changes to the nature of service due to AMI deployment, broadening the definition of "written Communications" to reflect digital communications, and various other modifications reflecting the changing nature of utility service and new customer offerings;[877] and

WHEREAS, most of these proposed changes are unopposed by the parties. The Council finds the unopposed proposed changes to be reasonable; and

WHEREAS, one proposed change was objected to by the Air Products and the Advisors, specifically, the proposed change to Section 11 Continuity of Service, which would have changed ENO's responsibility for loss or damages caused by the failure or other defects of service, which both Air Products and the Advisors objected to as inappropriate; [878] and

[876] Ex. No. ENO-6 at 59:4-9.
[877] Ex. No. ENO-6 at 59:18-62:6.
[878] Ex. No. AP-3 at 25:18-19, Air Products Initial Brief at 44, Advisors Initial Brief at 144.

WHEREAS, in its Reply Brief, ENO stated that it does not object to Air Products' recommendation that ENO's proposed change to the Continuity of Service provision in the Service Regulations not be adopted (though ENO objected to the Advisors' characterization of the effect of the provision);[879] and

WHEREAS, the Council finds the proposed changes to the Service Regulations, except for the proposed change to Section 11 Continuity of Service, to be reasonable. The Council rejects the proposed change to Section 11 Continuity of Service; and

CITY OF NEW ORLEANS BILLING ISSUES

WHEREAS, CCPUG witness Baron recommends that the Council require ENO to establish a working group, following completion of the rate case to address billing issues. ENO opposes this recommendation, noting that CCPUG did not identify the aspects of billing that the City claims to be at issue, and recommends that instead the City work with its account representative to address any billing issues. The Advisors agree that a working group likely is not necessary to resolve the City's concerns and are willing to work with the City and ENO to assist in resolving these concerns to the City's satisfaction. CCPUG is supportive of the Advisors' suggestion, but still urges the formation of a working group; and

WHEREAS, the Council finds it unnecessary to establish a formal working group to address the City's issues at this time, but directs its Advisors to work with the City and with ENO to resolve the City's billing issues; and

TAX BENEFITS RELATED TO AMI

WHEREAS, as part of the AMI deployment ENO must retire certain related existing plant, such as meters, prior to its full recovery through depreciation ("Stranded Plant").[880] The Advisors

[879] ENO Reply Brief at 118.

note that the retirement of this Stranded Plant is associated with ENO's per-book recording of ADIT liabilities.[881] In its Revised Application, ENO incorrectly removed ADIT related to Stranded Plant from rate base in the amounts of $6,227,006 and $823,146 for electric and gas respectively.[882] Intervenors did not comment on ENO's exclusion of this ADIT from its rate base; and

WHEREAS, the Advisors recommend that ENO's rates should reflect the economic benefit it enjoys due to cost-free capital. Out of an abundance of caution for ENO's unspecified "potential violations" of IRS normalization rules, an appropriate mechanism to recognize ENO's cost-free capital is a regulatory liability.[883] As the economic benefit to ENO of Stranded Plant ADIT is undisputed, the Advisors recommend the Council recognize the benefit to ENO of cost-free capital and direct ENO to create regulatory liabilities in the amount of $6,227,006 and $823,146 for electric and gas respectively and include those liabilities in ENO's regulatory rate base;[884] and

WHEREAS, the Council finds that the Advisors' proposal is reasonable; and

MISCELLANEOUS ISSUES

(1) *Error in ENO's Calculation of Electric Taxes*

WHEREAS, in response to discovery in the instant proceeding, ENO has acknowledged an error in its calculation of electric taxes, which the Advisors estimate and present correcting adjustments in the below table;

[884] Ex. No. ADV 8 at 37:10-13, Advisors Initial Brief at 148.

Advisor Adjustment ADV06 Period II		
Account	**Debit**	**Credit**
410101	$141,633	
190221		$141,633
410120	$22,872	
190222		$22,872

WHEREAS, the Council finds that ENO should correct for this error as part of its compliance filing; and

(2) *ENO's $1/Year Per Gas Meter Gas Research and Development Charge*

WHEREAS, ENO has proposed a $1 per year per gas meter gas research and development charge to fund ENO's participation in certain industry technology development groups; and

WHEREAS, the Advisors testified that, while such expenditures may involve energy efficiency and environmental benefits, and thus are indicative that they may be prudently incurred costs, ENO's proposed per meter charge is not necessary, would constitute single-issue ratemaking, and such costs should instead be recovered through ENO's gas base rates; and

WHEREAS, the Council is persuaded by the Advisors' arguments and finds that, while ENO's participation in the groups it discusses may be prudent, a special per-meter charge is not justified; and

OTHER MISCELLANEOUS ISSUES

WHEREAS, ENO is proposing that the Council approve of certain modifications to the Service Regulations Applicable to Electric and Gas Service by ENO.[885] The proposed modifications vary in purpose: addressing minor modifications necessary to reflect the changing

[885] Ex. No. ENO-55 at 45.

nature of service due to innovations such as the impending deployment of AMI and new customer offerings and billing options the Company proposes to make available to customers[886] as well as the combination of the Algiers and Legacy ENO service territories into a single territory; and

WHEREAS, the Advisors reviewed and had no objection to and no other party objected to ENO's proposed changes related to Datalink and other related riders changing due to AMI;[887] the updates to fees for certain service schedules;[888] and the discontinuation of certain schedules;[889] and

WHEREAS, in light of the lack of objection to these proposals by any party, including the Council's Advisors, the Council finds these proposals to be reasonable; and

WITHDRAWN PROPOSALS

WHEREAS, ENO proposed a Pre-pay Electric Service ("PES") Option and Pre-pay Gas Service ("PGS") Option (Schedules PES and PGS) which are prepaid billing options for residential customers.[890] ENO's proposal would be a voluntary billing option enabled by AMI and supporting technology.[891] The Advisors support the development of a pre-pay option for ENO customers.[892] However, in its rejoinder testimony, ENO suspended its request for approval of the pre-pay option due to delays and increased complexity in the integration of the AMI customer web portal with the Company's legacy IT and billing systems.[893] ENO states that the expected additional integration and IT development efforts to fully deploy pre-pay service are more complex than were originally

[886] Ex. No. ENO-55 at 45-46.
[887] Advisors' Initial Brief at 141-142.
[888] Advisors' Initial Brief at 144-146.
[889] Advisors' Initial Brief at 146-147
[890] Ex. No. ENO-55 at 42.
[891] Ex. No. ENO-55 at 42-43; Ex. No. ENO-19 at 4:20-5:2.
[892] Advisors' Initial Brief at 124.
[893] Ex. No. ENO-13 at 14:4-8.

envisioned.[894] Because ENO has suspended this request, the Council will not consider ENO's pre-pay proposal at this time; and

WHEREAS, in its Revised Application, ENO proposed a voluntary fixed billing option for residential customers under which, in exchange for paying a premium over what the standard residential service rate would be, customers receive a monthly fixed bill that will not change over the contract period.[895] However, in response to the Advisors' testimony, ENO withdrew this proposal in its Rebuttal Testimony.[896] Therefore, the Fixed Billing proposal also will not be addressed by the Council at this time; and

<u>COMPLIANCE FILING</u>

WHEREAS, the Revised Application discusses ENO's making a compliance filing resulting from a decision from this proceeding; and

WHEREAS, this resolution does not and is not intended to specify ENO's exact revenue requirements or exact rates that would allow ENO to collect such revenue amounts; and

WHEREAS, this resolution directs ENO to make numerous adjustments to its proposed revenue requirements and rates; and

WHEREAS, it is not practical for the Council to calculate with precision the rates ENO should be allowed to implement to comply with each aspect of this resolution; and

WHEREAS, the Council desires for its Advisors to confer with ENO as soon as practicable to share with ENO the Advisors' opinion as to the revenue requirement and rate class impacts of this resolution; and

[894] Ex. No. ENO-13 at 14:10-12.
[895] Ex. No. ENO-55 at 44.
[896] Ex. No. ENO-21 at 2:10-11.

WHEREAS, in a motion in the instant proceeding filed before the Hearing Officer on July 11, 2019, ENO stated that it maintained its commitment that the effective date of the rates approved by the Council will be the first billing cycle of August; and

WHEREAS, in the same motion in the instant proceeding filed before the Hearing Officer on July 11, 2019, ENO discussed that a Council determination in the instant proceeding by September would allow ENO to implement rates with the first billing cycle of November; and

WHEREAS, the Council desires for ENO to demonstrate how it will comply with each provision of this resolution by making a compliance filing within 30 calendar days of the adoption of this resolution providing all relevant documents for each of electric and gas, including,

1. Total company retail revenue requirements subtotaled by rate class (for electric, each of the nine customer classes identified in the Revised Application).
    a. A detailed set of work papers demonstrating that such revenue requirements are in full compliance with each provision of this resolution and do reflect costs not approved by the Council.
2. A computation of each fee, charge, rate, proscribed credit, or other mechanism by which ENO receives revenue or credits against revenue requirement, that, when applied to ENO's Period II billing determinants, would allow ENO to collect its revenue requirement for each rate class.
3. A computation of all credits and charges appropriate and required for ENO's new rates to be effective as of the first billing cycle of August 2019.
4. Interim rate adjustment riders for each of electric and gas to provide required credits by rate class consistent with the excess revenues collected from each rate class from

the first billing cycle of August 2019 through the last billing cycle before new rates go into effect.

a. The allocation of credits among the rate classes shall, to the extent practicable, reflect the allocation method employed to collect excess revenues (*e.g.*, volumetric, demand, base rate).

b. The calculation of credits shall reflect carrying charges reflective of the source of excess collections (*e.g.*, excess collections through the FAC shall accrue carrying charge credits at the FAC's over/under rate). For excess collections received from sources not having an over/under provision (*e.g.*, base rates), the FAC's over/under rate shall apply.

c. For any rider having a true-up mechanism and which under-collected its approved revenue requirement through July 31, 2019, a provision to first apply over collections from August 1, 2109 to the under-collection balance.

d. For electric, and to the extent reasonably practicable, a mechanism to return over collections according to service area (*i.e.*, the east and west bank of the Mississippi River).

e. The interim rate adjustment rider may itself have a true-up provision.

f. The interim rate adjustment rider may return over collections over a reasonable period of time not to exceed three months.

5. Copies of all documents, such as service schedules, riders (including the E-FRP and GFRP riders), or terms affecting ENO's service and rates that are required to be altered to comply with this resolution, with rates presented therein.

6. For each ratemaking treatment ordered herein that is not consistent with ENO's Revised Application, a description of how ENO has implemented such treatment and in which workpaper or other document its implementation may be mathematically reviewed; and

WHEREAS, the Council does not seek to permit ENO to include adjustments as part of its compliance filing that are not ordered herein that ENO may regard as ancillary consequences of this resolution's ratemaking directives or treatments; and

WHEREAS, the Council desires for ENO and the Advisors to work together to ensure ENO's compliance filing reflects every aspect the orders in this resolution; and

WHEREAS, the Council desires for the Advisors to review ENO's compliance filing and to have all relevant information required for such a review made available by ENO; and

WHEREAS, the Council desires for the Advisors to have fifteen (15) business days to review ENO's compliance filing for accuracy, compliance with this resolution, and consistency with established Council ratemaking practices; and

WHEREAS, should the Advisors identify any error or deficiency in ENO's compliance filing, or require additional information to validate any part of ENO's compliance filing, the Council desires for the Advisors to identify and report to ENO such error or deficiency along with any documentation and proposed correction, and then for ENO and the Advisors to work together to resolve all issues; and

WHEREAS, the Council desires for the Advisors to, at the conclusion of their review of ENO's compliance filing, to state whether ENO's compliance filing complies fully with this resolution and is appropriate in all material aspects or to identify any remaining deficiencies; and

WHEREAS, the Council desires that, unless the Advisors conclude that ENO's compliance filing results in rates that are wholly inappropriate, that retail rates in compliance with this resolution be affected, as soon as practicable by ENO notwithstanding any unresolved issues; and

WHEREAS, the Council desires that, in the event there are disputes regarding ENO's compliance filing that cannot be resolved through good faith efforts by ENO and the Advisors, the Advisors should report such issues, along with documentation and the Advisors' recommended correction, to the Council for the Council's evaluation; and

WHEREAS, the Council desires that any corrections to ENO's compliance filing that are resolved after new rates are affected be made effective as of the first billing cycle of August through the interim rate adjustment rider's true-up mechanism; and

WHEREAS, the Council has reviewed ENO's Revised Application and the record and considered all arguments raised therein, to the extent that any specific argument is not herein addressed, the Council has reviewed such argument and found that it was duplicative, cumulative, or otherwise did not have sufficient impact on the Council's decision to warrant discussion herein;

NOW THEREFORE

BE IT RESOLVED BY THE COUNCIL OF THE CITY OF NEW ORLEANS THAT:

1. ENO's ROE shall be set at 9.35% and shall operate as a bandwidth midpoint for purposes of the formula rate plan approved in this proceeding.
2. ENO's WACC shall be based on an equity ratio equal to the lesser of ENO's actual equity ratio or 50% and shall be used for all rate ratemaking purposes.
3. ENO's proposed depreciation rates are approved, except:
    a. ENO shall employ a 40-year depreciable life schedule for UPS effective August 1, 2019.

b. ENO shall employ a 50-year depreciable life schedule for NOPS.

c. ENO shall amortize the general plant reserve deficiency over a 20-year period.

4. ENO's proposal to exclude FIN 48 ADIT liability balances from its rate bases is denied.
5. ENO's proposal to include NOLCF ADIT asset balances in its rate bases is denied.
6. ENO shall employ its then current WACC with each calculation of Rider SSCO's rate.
7. ENO is directed to create regulatory liabilities in the amount of $6,227,006 and $823,146 for electric and gas respectively and include those liabilities related to Stranded Plant ADIT in ENO's regulatory rate base.

8. ENO's proposal to recover Restrictive Stock Incentive Plan costs is denied.

9. ENO's proposed pension asset adjustment is approved.

10. ENO's proposed GIRP rider is denied.

a. ENO's GIRP infrastructure costs incurred as proformed through the end of 2019 and generally approved by Resolution R-17-38 are approved for cost recovery through base rates.

b. Within 120 days from the date of this order, ENO is directed to propose, for Council consideration, a rate of gas distribution pipe installation and dollar investment that is required to maintain the safe operation of ENO's gas system including potential measures to mitigate the identified impact on ratepayers.

c. Within 120 days from the date of this order, ENO is directed to convene a working group composed of the Advisors, ENO, and Intervenors to explore appropriate cost mitigation measures.

d. ENO's recovery of utility conflict survey costs is approved and ENO is directed to recover its related costs through base rates.

11. ENO's proposal to allocate certain PPA costs on a volumetric basis is denied.

12. The Council denies CCPUG's recommendations to:

a. Remove Capital Storm Restoration Costs from Plant

b. Remove Depreciation Expense Associated With Capital Storm Restoration Costs

c. Remove Amortization of Algiers Migration Costs

d. Reduce Depreciation Expense – Correct Paterson Solar Depreciation Rate

e. Remove Reduction to ADIT for Excess ADIT Amortization in 2019

f. Remove Algiers Migration Costs Net of ADIT

g. Reduce Depreciation Expense – Use 0% Net Salvage for Union Power Block #1

h. Extend Amortization of Algiers Transaction and Migration Costs to 10 Years

i. Remove Plant, A/D, and ADIT Proforma Adjustments Related to 2019 Additions

j. Remove Depreciation Expense Related to 2019 Plant Additions.

13. The Council approves CCPUG's recommendations to,

    a. Correct Cash Working Capital to Include Dividend Component of Return on Equity

    b. Reduce Depreciation Expense – Use 40 Year Service Life for Union Power Block #1

    c. Extend Amortization Period for General Plant Reserve Deficiency from 10 Years to 20 Years

    d. Remove Forecast 2019 Increases in Payroll and Related Expenses

14. The utility's total revenue requirements, as determined by compliance with each of the Council's directives in this Resolution, will be recovered from each customer class on the basis of the Advisors' proposal for customer class revenue requirements as indicated in Advisors' Exhibits VP-20 and VP-21 for the electric and gas utilities respectively.
15. ENO's proposal to eliminate and consolidate customer classes, including the existing Algiers electric tariffs, to be combined into nine electric customer rate classes is approved.

16. ENO is directed to provide a complete cost of service analysis in support of the NJ customers' rates as part of future Council rate actions. ENO is further directed not to execute any new NJ contracts without express Council approval.

17. ENO's DGM Rider is rejected and ENO is directed to recover its costs related to grid modernization through base rates.

18. The AART Plan shall be adjusted consistent with the Advisors recommendations except that instead of the mitigation plan being funded by the Legacy ENO residential customers, it shall be funded by the Large Electric, Large Electric High Load Factor, High Voltage, and Large Interruptible rate classes in proportion to their base rate revenue requirements.

19. ENO's proposed FAC Rider is approved as corrected by the Advisors.
20. ENO's proposed PGA Rider is approved as corrected by the Advisors.

21. ENO shall revise its proposed PPCACR Rider in accordance with the recommendations made by the Advisors for a PPCR Rider.

22. The MISO Cost Recovery Rider is approved as proposed.

23. The Company's $8.07 electric residential customer charge shall remain unchanged.
24. ENO's proposed AMI Riders and customer charges are denied.
25. The Council approves ENO's proposed electric and gas FRP mechanisms with the following modifications:
    a. Total utility cost of service, including total ENO revenues and expenses shall be utilized in the FRP evaluation;

    b. The Advisors' proposed provision that "ENO may propose other known and measurable costs that are supportable and expected to be incurred in the prospective 12 months following the FRP evaluation Period" shall be add to FRP Attachment C, Evaluation Period Adjustments, paragraph 8.

    c. ENO's proposed RIM is rejected.

    d. The electric FRP decoupling revenue adjustment for each customer class should be determined by comparing the evaluation period fixed and variable revenue by class with the FRP evaluation period allocation of total ENO fixed and variable revenue requirement.

    e. No NOPS costs shall be included in the FRP mechanism until such time as the construction of NOPS and associated costs have been approved through a final judgment of the Council. To the extent that the Council's judgment becomes final, the proforma adjustments related to NOPS shall be included in the FRP for the 12-month period subsequent to the FRP evaluation period, which would encompass calendar year 2020 for the first FRP. If the NOPS updated revenue requirement is included as a prospective proforma adjustment in the bandwidth evaluation of the proposed E-FRP filed in April 2020, the NOPS in-service rate adjustment, beginning with the month following COD, would be effective until NOPS cost recovery is included in the E-FRP revenue adjustment of the first FRP. If the NOPS updated revenue requirement filing is not included as a prospective proforma adjustment in the proposed E-FRP filed in April 2020, the NOPS in-service rate adjustment, beginning with the month following COD, would be effective until NOPS costs are included in the RPE bandwidth evaluation of the following E-FRP. The E-FRP provision should include an allocation of NOPS costs based on the rate case production demand allocation factor, rather than total base rate costs.

26. ENO's decoupling proposal shall be modified such that a full decoupling mechanism shall be filed with each electric E-FRP evaluation, with total allocated costs of service for each customer class included in the decoupling revenue adjustment, and the customer rate class allocation factors be updated annually with current billing determinants. The decoupling adjustment shall be applied to all customer classes if the E-FRP revenue adjustment is outside the bandwidth. However, ENO shall, for rate classes Master Metered Non-Residential, Large Electric High Voltage and Large Interruptible Service, implement a decoupling revenue adjustment cap of 10% which will apply to each of the 3 annual E-FRP evaluation period revenue adjustments provided that the total electric utility FRP revenue adjustment for that evaluation does not exceed 10%. A new baseline of customer class fixed and variable revenue requirements shall be determined in each E-FRP from an

allocation of costs and a return component based on the rates of return corresponding to the customer class total revenues set in the instant docket. Any adjustments that may be needed to the relative rates of return will be such that those adjustments move the relative customer class rates of return toward the utility's rate of return based on the weighted average cost of capital. The revenue deficiencies/excesses shall be determined for each customer class by comparing the E-FRP customer class total revenue requirements with the customer class evaluation period total actual revenues, with the decoupling adjustments applied within each customer class using updated billing determinants excluding the customer charge. The decoupling adjustment shall apply to proforma revenue requirements and billing determinants in the E-FRP rate effective period, based upon updated allocation factors and billing determinants in each E-FRP.

27. ENO's Green Pricing Proposal is be approved with the following modifications:

    a. to the extent that the Council establishes a definition of "renewable resources" in Council Docket No. UD-19-01, RECs used for the Green Power Option must originate from sources meeting that definition;

    b. to the extent the Council adopts a requirement in Council Docket No. UD-19-01 that RECs be certified and/or tracked through a particular program(s), such as Green-e, then RECs used for the Green Power Option must be certified and/or tracked in the same manner, however, if the Council does not establish such a requirement in UD-19-01, then RECs shall be certified through Green-e (or such other certification as the Council may approve in the future);

    c. ENO's pricing proposal is approved with the modification that in the instance where there are not enough customers participating in the Green Power Option that those customers could reasonably be expected to bear the full costs of the program under the approved pricing structure, ENO should be allowed to recover remaining costs from non-participating ratepayers after submitting such costs to the Council for review and demonstrating to the Council's satisfaction that the costs were prudently incurred, along with a request for Council authorization to either alter the program to ensure that there is reasonable assurance that costs of the program will be paid by participating customers going forward, or a request to terminate the program; and

    d. to the extent that there is not a final Council decision in Docket No. UD-19-01 prior to the implementation of the Green Power Option, ENO shall be allowed to utilize any Green-e certified RECs until such time as the Council renders a decision in UD-19-01, at which point, ENO must conform its use of RECs to the Council's definition of renewable resources and certification and/or tracking requirements on a going-forward basis.

28. Both ENO's and BSI's Community Solar proposals are rejected.
29. The Interim EECR Rider is approved.
30. The proposed Rider DSMCR is rejected. In its place an EECR Rider consistent with the Advisors' proposal is approved. LCFC shall be addressed through the decoupling process and shall not be included in the EECR Rider.

31. ENO's proposal to extend its MVLMR and MCDRR to its full service territory is approved. ENO is directed to add customer support to the program, including the provision of cost estimates to interested customers to encourage understanding of and participation in the program.
32. BSI's CLEP proposal is rejected, as is BSI's request that the Council form a working group to implement CLEP.
33. ENO's proposed Rider EVCI is approved.
34. ENO is authorized to invest of up to $500,000 in public EV charging infrastructure that would provide free EV charging services at roughly 30-50 locations and shall consider stakeholder input as to the siting of such locations in Council Docket No. UD-18-01.
35. ENO is authorized to continue with the eTech program of rebates for the installation of EV chargers, with the program to be included in the Energy Smart Implementation Plan for PY 10-12. In the proceeding considering that Implementation Plan, the parties should develop a method of assessing the success of the eTech program separate and apart from the kWh and any kW savings goals established in the Implementation Plan for PY10-12 such that increased usage related to the success of the eTech plan does not negatively impact ENO's ability to achieve the savings goals related to other measures.
36. The proposed changes to the Service Regulations, except for the proposed change to Section 11 Continuity of Service, are approved. The proposed change to Section 11 Continuity of Service is rejected.
37. ENO shall correct tax errors in its Revised Application related to FERC Accounts 410 and 190.
38. ENO shall create a regulatory liability and enter such liability's balance in its rate base to reflect the economic benefit of cost free capital related to retired meters.
39. ENO's proposed $1/yr. per gas meter research and development charge is denied.
40. ENO shall make a compliance filing with the Council within 30 calendar days of the adoption of this resolution providing all relevant documents for each of electric and gas, including,
    a. Total company retail revenue requirements subtotaled by rate class based on Period II (for electric, each of the nine customer classes identified in the Revised Application).
        i. A detailed set of work papers demonstrating that such revenue requirements are in full compliance with each provision of this resolution and do reflect costs not approved by the Council.
    b. A computation of each fee, charge, rate, proscribed credit, or other mechanism by which ENO receives revenue or credits against revenue requirement, that, when applied to ENO's Period II billing determinants, would allow ENO to collect its revenue requirement for each rate class.
    c. A computation of all credits and charges appropriate and required for ENO's new rates to be effective as of the first billing cycle of August 2019.
    d. Interim rate adjustment riders for each of electric and gas to provide required credits by rate class consistent with the excess revenues collected from each rate class from

the first billing cycle of August 2019 through the last billing cycle before new rates go into effect.

i. The allocation of credits among the rate classes shall, to the extent practicable, reflect the allocation method employed to collect excess revenues (*e.g.*, volumetric, demand, base rate).

ii. The calculation of credits shall reflect carrying charges reflective of the source of excess collections (*e.g.*, excess collections through the FAC shall accrue carrying charge credits at the FAC's over/under rate). For excess collections received from sources not having an over/under provision (*e.g.*, base rates), the FAC's over/under rate shall apply.

iii. For any rider having a true-up mechanism and which under-collected its approved revenue requirement through July 31, 2019, a provision to first apply over collections from August 1, 2109 to the under-collection balance.

iv. For electric, and to the extent reasonably practicable, a mechanism to return over collections according to service area (*i.e.*, the east and west bank of the Mississippi River).

v. The interim rate adjustment rider may itself have a true-up provision.

vi. The interim rate adjustment rider may return over collections over a reasonable period of time not to exceed three months.

e. Copies of all documents, such as service schedules, riders (including the E-FRP and GFRP riders), or terms affecting ENO's service and rates that are required to be altered to comply with this resolution, with rates presented therein.

41. For each ratemaking treatment ordered herein that is not consistent with ENO's Revised Application, a description of how ENO has implemented such treatment and in which workpaper or other document its implementation may be mathematically reviewed.
42. To the extent not otherwise modified in this Resolution, ENO's remaining proposals are approved as filed by ENO.
43. The Council's Utility Advisors are directed to work with the City and ENO to resolve the City's outstanding billing issues.

THE FOREGOING RESOLUTION WAS READ IN FULL, THE ROLL WAS CALLED ON THE ADOPTION THEREOF, AND RESULTED AS FOLLOWS:

YEAS: **Brossett, Giarrusso, Gisleson Palmer, Moreno, Nguyen, Williams - 6**

NAYS: **Banks - 1**

ABSENT: **0**

AND THE RESOLUTION WAS ADOPTED.

THE FOREGOING IS CERTIFIED TO BE A TRUE AND CORRECT COPY

Lora W. Johnson

CLERK OF COUNCIL

STATE OF VERMONT
PUBLIC UTILITY COMMISSION

Case No. 19-0513-TF

Investigation into the tariff filing of Vermont Gas Systems, Inc. proposing a change in rates and use of the System Expansion and Reliability Fund	Hearings at Montpelier, Vermont September 9, 2019

Order entered: 10/23/2019

PRESENT: Sarah Hofmann, Commissioner

APPEARANCES: Daniel C. Burke, Esq.
Vermont Department of Public Service

Owen McClain, Esq.
Sheehey Furlong & Behm P.C.
for Vermont Gas Systems, Inc.

Table of Contents

I. <u>INTRODUCTION</u>

This case involves the Vermont Public Utility Commission's ("Commission") investigation into Vermont Gas Systems, Inc.'s ("Vermont Gas") tariff filing requesting an overall rate decrease in the amount of 2.7%, which reflects a 5% increase in daily access and distribution charges ("non-gas rates"), a 16.6% decrease in natural gas costs, and a $6.4 million withdrawal from the System Expansion and Reliability Fund ("SERF").[1]

In today's Order, the Vermont Public Utility Commission ("Commission") determines that Vermont Gas's requested rate increase of 5% should be approved, effective for bills rendered on or after November 1, 2019, but its revenue requirements should be revised to reflect

[1] The Commission approved the establishment of the SERF in 2011. Docket 7712, Order of 9/28/11. Under the Commission's ruling, in lieu of decreasing rates by approximately 5% to reflect lower natural gas costs, Vermont Gas was permitted to keep rates unchanged and place the difference into the SERF.

a 9.2% return on equity, an 8% short-term debt ratio, and various adjustments to Vermont Gas's cost of service as described below. Vermont Gas's requested SERF withdrawal should be adjusted accordingly. We also require Vermont Gas to provide certain disclosures to its customers, the Commission, and the Vermont Department of Public Service ("Department") regarding the pricing of its untariffed service offerings and to provide status updates to the Commission and the Department regarding its in-line and cross-bore inspection programs.

II. Procedural History

On February 15, 2019, Vermont Gas filed a petition requesting a 5% increase in firm non-gas rates to be effective November 1, 2019. Vermont Gas also requested that the Commission suspend the effectiveness of the proposed tariffs pursuant to Section 226(a) with implementation occurring on November 1, 2019, after the conclusion of the Section 227(a) seven-month review period. Vermont Gas also requested use of $6.4 million of the SERF to reduce the cost of service and to smooth and mitigate rate impacts related to the Addison Natural Gas Project ("ANGP").

On February 22, 2019, the Commission suspended the effectiveness of the proposed tariffs and opened this investigation into the proposed rate change.

On April 11, 2019, the Commission held a prehearing conference.

On April 16, 2019, the Commission issued a procedural order to set forth the case schedule, which established April 24, 2019, as the deadline for motions to intervene.

No motions to intervene were filed.

Also on April 16, 2019, the Commission convened a public hearing at Colchester High School. Two members of the public attended the public hearing.

On July 3, 2019, in a separate proceeding, Vermont Gas requested approval of a one-year extension of its alternative regulation plan through September 30, 2020.

On August 15, 2019, the Commission approved the one-year extension of the Company's alternative regulation plan, which includes the purchase gas adjustment provision for recovery of gas-related costs (Case No. 19-2932-PET).

Between March 15, 2019, and July 19, 2019, the Department served three rounds of discovery on Vermont Gas. The Department submitted prefiled testimony and surrebuttal testimony on May 30, 2019, and August 9, 2019, respectively. Vermont Gas served two rounds of discovery on the Department. On July 12, 2019, Vermont Gas filed rebuttal testimony.

On September 9, 2019, the Commission held an evidentiary hearing in this case. At the evidentiary hearing, the testimony and exhibits listed in Joint Exhibit-1 were admitted into the evidentiary record. Commissioner Hofmann was present at the evidentiary hearing. Chair Roisman and Commissioner Cheney were not present at the evidentiary hearing but have read the record for the proceeding.

On September 25, 2019, the parties filed their post-hearing briefs and proposed findings of fact.

On October 2, 2019, the parties filed reply briefs.

III. Public Hearing and Comments

On April 16, 2019, the Commission convened a public hearing at Colchester High School. Two members of the public attended and spoke at the public hearing. The Commission also received four written public comments during the proceeding. Concerns raised in the comments included the amount of the proposed non-gas rate increase relative to inflation and decreases in gas costs, energy efficiency charges, and the use of the SERF.

IV. Findings

A. General

1. This case addresses the non-gas rate components of Vermont Gas's cost of service. These components are the daily access and distribution charges and are collectively identified as the "Base Rate." The natural gas charge component of the Company's rates is modified on a quarterly basis pursuant to the purchase gas adjustment approved in Docket Nos. 8698 and 8777 as part of Vermont Gas's alternative regulation plan and as extended through September 2020 in Case No. 19-2932-PET. Lauren Hammer, Vermont Gas ("Hammer") pf. at 2-4; Eileen Simollardes, Vermont Gas ("Simollardes") pf. at 4; exh. VGS-LH-2.

2. The Test Year is the 12-month period ending December 31, 2018, and the Rate Year is the 12-month period from October 1, 2019, through September 30, 2020. Hammer pf. at 4-5.

3. Vermont Gas initially proposed a firm non-gas rate increase of 5%, return of $6.4 million from the SERF, and a decrease in gas costs of 16.6%, resulting in an overall rate decrease of approximately 2.7%. Simollardes pf. at 4; Hammer pf. at 4; Exh.VGS-LH-2.

4. The Department initially recommended reducing Vermont Gas's proposed revenue requirement by $2.97 million, which consisted of $1.94 million of adjustments to VGS's proposed cost of service and an approximately $1.03 million reduction to VGS's proposed return on rate base. Scott Wheeler, Department ("Wheeler") pf. at 2.

5. The Department proposed to leave Vermont Gas's requested base rate increase of 5% in place, but reduce SERF withdrawals from $6.4 million to approximately $3.45 million to account for the Department's recommended adjustments to Vermont Gas's revenue requirements. Wheeler pf. at 22.

6. Vermont Gas agreed to remove 50% of its short-term incentive plan from its cost of service based on the Department's proposals and also adjusted for a change in gross receipts tax ("GRT"). The GRT was increased from 0.3% to 0.525% effective July 1, 2019. To account for the changes, Vermont Gas maintained its proposed 5% increase to Base Rates but reduced its proposed SERF withdrawal to $6.25 million. Simollardes pf. reb. at 21, 23; exh. VGS-AK-2.

7. In response to additional information provided by Vermont Gas during discovery and rebuttal, the Department also revised its recommended adjustments to Vermont Gas's cost of service in several areas, including Transmission Expense, Distribution Expense, Payroll Costs, and an anticipated increase in Vermont Gas's insurance costs. Wheeler pf. sur. at 2, 4, 6-8.

8. The Department's revised recommended adjustments result in corresponding flow-through adjustments to benefits and income taxes. The Department also agreed with Vermont Gas's adjustment based on the changes to the gross receipts tax. Simollardes pf. reb. at 21; Wheeler pf. surreb. at 3-4, 11.

9. After the revised cost-of-service adjustments recommended by the Department, the Department recommends a 5% base rate change and a $4.325 million SERF withdrawal. Wheeler pf. sur. at 12.

10. The remaining cost-of-service items in dispute are summarized in the table below.

COS Category	VGS	DPS	Difference	Percentage
Cost of Capital	$19,351,598	$18,322,977	$(1,028,621)	53.06%
Income Taxes	$ 5,373,675	$ 4,993,475	$(380,200)	19.61%
Outside Legal Services	$ 812,132	$ 562,855	$(249,277)	12.86%
Payroll (STIP 50% Conceded)	$10,054,294	$ 9,947,585	$(106,709)	5.50%
Outside Services Other	$ 1,047,572	$ 958,127	$(89,445)	4.61%
Benefits	$ 3,725,479	$ 3,707,394	$(18,085)	0.93%
Depreciation	$11,752,860	$11,711,352	$(41,508)	2.14%
Gross Receipts Taxes	$ 557,209	$ 546,976	$(10,233)	0.53%
Weatherization Taxes	$ 791,550	$776,899	$(14,651)	0.76%
Total COS Adjustments			$(1,938,729)	100.00%

Wheeler pf. sur. at 11.

11. Disagreements related to benefits are a flow-through change due to the disagreement over payroll. Disagreements related to depreciation are a flow-through change related to a disagreement over the inclusion of contingent costs related to Vermont Gas's customer information system capital project. Differences on gross receipts taxes, income taxes, and weatherization taxes are flow-through changes related to disagreements on cost-of-service issues. Wheeler pf. sur. at 11; Simollardes pf. reb. at 3-4.

Discussion

Disputes remain between Vermont Gas and the Department regarding the following components of the Company's proposed cost of service: (1) the appropriate cost of capital, including the return on equity ("ROE") and short-term debt ratio; (2) the appropriate amount for certain operating expenses, including outside services and payroll; and (3) the appropriate amount of construction work in progress ("CWIP") and contingencies to be included in rate base.

Although the Department disputes the items above, the Department has agreed to the overall proposed increase of 5% for non-gas rates. To account for the recommended reductions while maintaining the 5% increase, the Department has proposed a decrease in the amount that Vermont Gas is allowed to withdraw from the SERF.

We discuss each issue, and the additional issue of untariffed services, below.

B. <u>Capital Structure and Return on Equity</u>

12. Vermont Gas's current authorized return on equity ("ROE") is 8.5%. This ROE was imposed on VGS for a three-year term as a result of a Memorandum of Understanding ("MOU") between VGS and the Department that was approved by the Commission in Docket 8710. Simollardes pf. at 8.

13. Vermont Gas and the Department agree that Vermont Gas's proposed capital structure split between 50% equity and 50% debt is reasonable. Richard Baudino, Department ("Baudino") pf. at 3, 33-34; Simollardes pf. reb. at 22; John Trogonoski, Vermont Gas ("Trogonoski") pf. reb. at 29.

14. Vermont Gas is forecasted to have an actual equity ratio of 50% during the Rate Year. Tr. 9/9/19 at 91-92 (Baudino); exh. PSD-RAB-7.

15. VGS's long-term debt of $120,000,000 is fixed and represents 45% of rate base. Exh. VGS-AK-2, Schedule 11.

16. Vermont Gas's historical short-term debt percentage has a three-year average of 9% and a five-year average of 7.6%. Vermont Gas's projected short-term debt percentages for 2019-2021 are 9.9% (2019), 8.4% (2020), and 8.4% (2021). Exh. DPS-RAB-6; exh. DPS-RAB-7.

17. Vermont Gas proposes a short-term debt percentage of 5.48%, which is the percentage of debt that remains after imputed long-term debt is subtracted from the 50% overall debt figure. The Department recommends a short-term debt percentage of 8%, which is between Vermont Gas's 3-year and 5-year historical average and close to the amount of short-term debt from Vermont Gas's last rate proceeding. Hammer pf. at 16-17; Exh. VGS-AK-2, Schedule 11; Simollardes pf. reb. at 22; Baudino pf. at 33-34; exh. DPS-RAB-6.

18. Vermont Gas's actual long-term and short-term debt percentages are 40.72% and 11.61%, respectively. Vermont Gas's total actual debt is 52.33% of its capital structure. Exh. VGS-AK-2, Schedule 11.

19. Vermont Gas recommends an ROE of 9.8% based on an analysis of the results from a discounted cash flow ("DCF") model, capital asset pricing model ("CAPM"), and a risk premium analysis. Vermont Gas concludes that a reasonable range for Vermont Gas's ROE is 9.52%-10.13%. Trogonoski pf. at 3, 51.

20. The Department recommends an ROE of 9.2% based primarily on a DCF analysis. The Department also used a CAPM analysis to test the reasonableness of its DCF results. The Department's analyses support a range of 8.84%-9.54%. Baudino at 3, 15, 31.

21. The Department calculated its DCF return on equity using the same proxy group of seven gas utilities selected by VGS. The Department excluded one company's growth rate of 25.5% from its analysis as an outlier. Exhibit PSD-RAB-3; Baudino pf. at 19–20, 23.

22. The average ROE authorized for the 2019 rate year for the seven gas distribution companies is 9.60%. The median ROE authorized for the 2019 rate year for gas distribution companies in New England is 9.50%. Each of these ROEs is the result of a settlement. Trogonoski pf. reb. at 7; Baudino pf. sur. at 8-9; tr. 9/9/19 at 49–50 (Trogonoski).

23. Long-term interest rates have declined during 2019, from 2.94% in April of 2019 to slightly above 2% as of the date of the evidentiary hearing. Baudino pf. at 7; Tr. at 36 (Trogonoski).

Discussion

There are three essential steps in setting the weighted average cost of capital in a utility rate case. First, we determine an appropriate capital structure. Second, we determine the cost of each capital component. Third, we determine the cost of each component according to its proportion of the total capital structure. The sum of these weighted capital components is the weighted-average cost of capital.

Capital Structure

The parties have agreed that 50%-50% split between debt and equity is reasonable. However, they disagree on the appropriate long-term and short-term debt allocations. Vermont Gas has calculated its proposed short-term debt percentage by first adjusting its equity-debt percentages to 50% as agreed. Vermont Gas then calculates an imputed ratio of actual long-term debt in the adjusted overall debt percentage using the actual long-term debt obligations. Because Vermont Gas's overall debt percentage is reduced from 52.33% to 50%, the imputed ratio results in long-term debt representing a larger percentage of overall debt. Vermont Gas allocates the remainder of the 50% debt percentage, 5.48%, to short-term debt.

The Department disagrees with Vermont Gas's proposed capital structure. The Department explains that capital structures are hypothetical and should reflect how a company actually finances its rate base. The Department notes that it agreed to Vermont Gas's proposed debt-equity ratio even though the actual equity ratio is lower than 50%, which results in a benefit to Vermont Gas.[2] According to the Department, allowing Vermont Gas to minimize its short-term debt percentage provides additional benefit to Vermont Gas and does not reflect Vermont Gas's historical short-term debt percentages or how Vermont Gas actually finances its rate base.

We conclude that Vermont Gas's proposed short-term debt percentage is too low. The percentage is below Vermont Gas's historical short-term debt percentages as well as Vermont Gas's forecasted short-term debt percentages, which supports the conclusion that Vermont Gas's short-term debt percentage will be higher than 5.48%.

Understating the short-term debt percentage would add to what is already an increased cost of capital due to the agreed hypothetical allocation of debt and equity. By increasing the equity percentage of Vermont Gas's capital structure from its actual value of 47.66% to a hypothetical value of 50%, Vermont Gas benefits from an increased contribution of equity to the weighted cost of capital. When Vermont Gas achieves 50% equity, which Vermont Gas states will occur during the Rate Year, the hypothetical equity ratio will reflect Vermont Gas's actual capital structure. However, reducing the weight of short-term debt in the hypothetical capital structure, as Vermont Gas proposes, would provide additional enhancement to Vermont Gas's weighted cost of capital and further depart from Vermont Gas's actual capital structure. Vermont Gas's forecasted 50% equity ratio in 2020 also includes a short-term debt ratio of 8.4%, which is close to the Department's recommended 8%.

The Department's proposed short-term debt ratio of 8% falls between the three- and five-year averages of Vermont Gas's historic short-term debt, and is also comparable to the forecasted level of short-term debt for 2020. We conclude that the Department's proposal reflects a reasonable level of short-term debt given Vermont Gas's current and historic capital structures, and more accurately reflects how Vermont Gas is actually financing its rate base. To

[2] Baudino pf. sur. at 18-19.

the extent that the increased short-term debt level results in an under-collection for long-term debt costs, the under-collection is more than made up for by the overweighting of equity in the weighted cost of service. For these reasons, we adopt 8% as the appropriate short-term debt ratio and direct Vermont Gas to revise its base rate filing accordingly.

Return on Equity

Vermont Gas and the Department also disagree on the appropriate ROE. It is well established that "[n]either the law nor regulatory precepts prescribe a specific methodology for setting the appropriate return on equity,"[3] and the Commission therefore has substantial discretion in determining an appropriate rate level.[4] The Commission has repeatedly emphasized that the critical element is the "reasonableness of the result" and not the methodology employed to reach it.[5] The basic standard for an appropriate rate of ROE is as follows:

> 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 and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[6]

The ROE analyses provided by Vermont Gas and the Department use the same proxy group of gas companies and follow similar methodologies for modeling expected returns. The significant difference is the assumptions underlying their ROE calculations. For example, Vermont Gas and the Department used the same sources for forecasted earnings growth, but used different time periods. The Department's witness also excluded an "unsustainable" growth forecast for one of the companies in the proxy group from his DCF analysis using median growth

[3] *In re Green Mountain Power Corporation*, Case No. 7175, Final Order at 12-13 (Dec. 22, 2006).

[4] *Investigation into Green Mountain Power Corporation's Tariff Filing,* Case No. 8190, Final Order at 21 (Aug. 25, 2014).

[5] *Id.*; *FPC v. Hope Natural Case Co.*, 320 U.S. 591, 602 (1944).

[6] *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679, 692-93 (1923).

rates.[7] Vermont Gas used a forecasted yield on 30-year Treasury bonds from 2020 to 2024, which was 3.9% and based on data from December 2018.[8] The Department, in contrast, used average yields on the 30-year Treasury bond and five-year Treasury note over a sample period from November 2018 through April 2019.[9] Rates declined throughout the sample period, with the yield on the 30-year Treasury bond at 2.94% in April of 2019.[10]

Both parties also compared the results of their ROE calculations to ROEs authorized for gas companies by other utility commissions in New England. Vermont Gas explains that the comparisons to "gas distribution companies with commensurate risk in other jurisdictions" provide a check on the reasonableness of the models used to calculate ROE.[11] The parties explain that the mean authorized 2019 ROE for gas companies in New England was 9.6% and the median was 9.5%.[12] The median and mean values are based on nine decisions authorizing ROEs issued between February 2018 and January 2019.[13] Each of the ROEs included in the data set was the result of a settlement.[14]

We conclude that the assumptions in the Department's analyses are a more accurate reflection of current economic conditions. The forecasted Treasury rates relied on by Vermont Gas have been shown to be inaccurate and, rather than increasing, have actually decreased over the course of this proceeding. The Department and Vermont Gas relied on the same sources for growth forecasts, but the Department's more recent financial data demonstrate a decline in growth forecasts compared to the older data used by Vermont Gas.[15] While Vermont Gas criticizes the Department's exclusion of the "unsustainable" growth forecast for one of the proxy

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[7] Baudino pf. at 23; exh. DPS-RAB-3; Trogonoski pf. at 10-11.
[8] Trogonoski pf. at 36.
[9] Baudino pf. at 30.
[10] Exh. PSD-RAB-4; *see also* Finding 23.
[11] Trogonoski pf. reb. at 6. Although the testimony and briefing discussed risks associated with Vermont Gas's small size, Vermont Gas's witness explained that he did not make any ROE adjustments based on that risk. Tr. 9/9/19 at 41 (Trogonoski); Trogonoski pf. at 45. Similarly, while the parties discussed potential regulatory risk and risks associated with Vermont's Comprehensive Energy Plan, it is not clear what effect, if any, those potential risks had on the proposed ROEs from the parties. We have not considered them in our analysis.
[12] *See* Finding 22.
[13] Trogonoski pf. reb. at 8.
[14] Tr. at 49–50 (Trogonoski).
[15] Baudino pf. at 35-36.

companies, we note that the ROE that results with that growth forecast included is still below Vermont Gas's proposed ROE.

Finally, the authorized ROEs for New England gas companies provided by Vermont Gas as comparison were all decided in 2018 or early 2019 and are all the result of negotiated settlements. As discussed above, economic forecasts have changed since these ROEs were authorized. Vermont Gas's proposed ROE, which is above the median and mean values of the comparison ROEs, moves in the opposite direction of these forecasts.

For these reasons, we adopt the Department's proposed ROE of 9.2% and direct Vermont Gas to revise its base rate filing accordingly.

C. Cost of Service

1. Outside Services

24. Vermont Gas and the Department disagree on two areas related to outside services. First, for both the Outside Services-Legal and the Outside Services-Other categories, Vermont Gas used a three-year average while the Department used a five-year average. Second, the Department made an additional adjustment to Outside Services-Other to remove expenses it alleged were related to ongoing investigations. Andrea Kean, Vermont Gas ("Kean") pf. reb. at 7-9.

25. Vermont Gas entered into a Memorandum of Understanding ("MOU") with the Department in Case No. 18-0409-TF.[16] Paragraph 28 of the MOU states that "Vermont Gas agrees to defer recovery of expenses associated with the Commission's pending investigations related to the Addison Natural Gas Project ("ANGP"), Case No. 17-4630-INV and Case No. 17-3550-INV until there is resolution of those matters." Hammer pf. at 11; Kean pf. reb. at 9.

26. Over the last several years, VGS has incurred on average nearly $400,000 more in legal costs than were included in rates. These added costs are after removing costs related to the ANGP litigation and investigation as required by the 18-0409-TF MOU. Kean pf. reb. at 7.

[16] *Tariff Filing of Vermont Gas Systems, Inc.*, Case No. 18-0409-TF, MOU dated 8/23/18.

27. The Department's proposed five-year average is more than $200,000 less than the average amount spent by Vermont Gas. Kean pf. reb. at 7.

28. The Department's five-year average includes two years (2014 and 2015) in which Vermont Gas's legal costs were over $400,000 less than the $698,659 incurred in the Test Year, after removing the costs associated with on-going investigations in Case Nos. 17-3550 and 17-4630. Keane pf. reb. at 8; exh. PSD-SW-3, Schedule 16.

29. The Department's recommendation for Outside Services-Legal is approximately $135,000 lower than Vermont Gas's Test Year expense ($698,659). Exhibit PSD-SW-3, Schedule 16.

30. Many of the legal costs in the past three years involved litigation related to the ANGP that were not required to be excluded pursuant to the MOU in Case No. 18-0409-TF and have now concluded. Tr. 9/9/19 at 60-64 (Simollardes).

31. Vermont Gas does not expect its legal costs to decrease from prior years in the Rate Year. Instead, Vermont Gas expects to incur additional legal costs in the Rate Year for matters involving regulatory approval of an alternative regulation plan, its Integrated Resource Plan, and short-term debt issuances that were not incurred in the Test Year. Tr. 9/9/19 (Kean) at 23; Tr. 9/9/19 (Simollardes) at 84.

32. In calculating its five-year average for Outside Services – Other, the Department excluded certain costs that it initially stated were related to ongoing investigations into the ANGP. Those costs were $540,998 in FY 2016 and $174,503 in FY 2017. Wheeler pf. at 15; exh. PSD-SW-3, Schedule 16.

33. The Department's witness agreed at the evidentiary hearing and in discovery responses that these costs were not related to excluded ANGP expenses pursuant to the MOU in Case No. 18-0409-TF, but were instead related to consultant costs for rate cases in FY 2016 and FY 2017. Tr. 9/9/19 at 135 (Wheeler); exh. VGS Cross 1; exh. VGS Cross 6.

Discussion

The Department and Vermont Gas's disagreement on rate year expenses for Outside Services – Legal and Outside Services – Other centers on a disagreement over the appropriate averaging period that should be used. Both parties cite to our recent explanation that

> [t]he Commission has used five-year and three-year averages to compute expected costs in rate cases in varying contexts. The choice of whether to use a five-year average or some other measure is highly fact-specific, and the "goal [is] to set rates for the future that realistically reflect the costs the Company will incur during the period for which rates are set."[17]

Last year, Vermont Gas and the Department agreed to use a five-year average for both Outside Services – Legal and Outside Services – Other. For Outside Services – Legal, Vermont Gas's actual legal costs for the 2018 fiscal year were $698,659, which exceeded the agreed-upon five-year average by more than $250,000.[18] The three-year average for Outside Services – Legal was $672,897 and would have been a more accurate estimate of Vermont Gas's actual legal expenses during the rate year.

The most significant driver of the difference between the three-year and five-year average is the inclusion of legal expenses from fiscal years 2014 and 2015, which are significantly below Vermont Gas's legal costs in recent years. Although, as the Department points out, the higher legal costs in recent years involved ANGP-related litigation that has now concluded, Vermont Gas does not expect its legal costs in the Rate Year to decrease due to ongoing regulatory obligations. Using a three-year average omits the lower legal costs of 2014 and 2015 and results in an average that more closely reflects Vermont Gas's actual legal costs in more recent years.

In contrast, Outside Services – Other shows significant variation from year to year without any clear trend. Given this variation, we conclude that a five-year average provides a better prediction of the costs that Vermont Gas will incur during the rate year. The Department, however, has also adjusted the average by reducing the costs for two years (excluding $540,998 for 2016 and $174,503 for 2017), which it states represent "unusual expenses." The Department has not explained why these expenses are unusual or why they should be excluded, stating only that the exclusions are consistent with the Department's recommendations from last year.[19] Absent an explanation of why these costs should not be allowed, we decline to exclude them.

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[17] *Tariff Filing of Green Mt. Power Corp.*, Case No. 19-1932-TF, Order of 8/29/19 at 8 (quoting *Tariff filing of Green Mountain Power Corp*., Docket 5428, Order of 1/4/1991 at 12*)*.

[18] Kean pf. reb. at 7-8; *Tariff Filing of Vermont Gas Systems, Inc.*, Case No. 18-0409-TF, Supp. Prefiled Testimony of E. Simollardes (8/24/18) at 3; exh. 1 to 18-0409-TF MOU, Schedule 7.

[19] Department Brief at 24; *see also* Tr. (9/9/19) at 132-137 (acknowledging that removing $540,998 from Outside Services – Other in FY 2016 resulted in a number that was significantly lower than any other year).

For the reasons above, we determine that Outside Services – Legal expenses should be determined using a three-year average as Vermont Gas proposes. Outside Services – Other should be calculated using a five-year average but without the Department's expense exclusions. We direct Vermont Gas to revise its base rate filing accordingly.

2. **Payroll**

34. The Department recommends that the Commission reduce VGS's proposed payroll expense by $106,709 based on Vermont Gas's approach to annualizing employee vacancies in calculating the salary component of its cost of service. Wheeler pf. sur. at 11.

35. Vermont Gas accounts for temporary vacancies and expected employee attrition in its Rate Year calculation for salary and benefits. A vacancy results in a reduction in the payroll costs for a position that is normally filled but is unfilled during some portion of the year. Simollardes pf. reb. at 16.

36. Vermont Gas developed its Rate Year payroll costs in this case using its actual payroll for calendar year 2018. Vermont Gas adjusted the Rate Year payroll by annualizing payroll for new positions created during the Test Year and for positions with vacancies beyond normal vacancy or turnover. Simollardes pf. reb. at 16.

37. Vermont Gas calculated a vacancy factor using the number of months that a position was not filled. If an employee left a position and the position was filled in the same year by a new employee, the vacancy counted in the cost of service was only the period that the position was actually vacant. Simollardes pf. reb. at 16; exh. VGS Cross 1.

38. The Department's witness agreed that if one employee was employed in the beginning of the year and worked only four months, and another employee was employed at the end of the year but only worked for the last six months, the appropriate vacancy factor would be two months. Tr. 9/9/19 at 129 (Wheeler).

39. The Department's witness agreed that its proposed reduction was an estimate and was not tied to actual vacancies at Vermont Gas. Tr. 9/9/19 at 131 (Wheeler).

Discussion

The Department argues that Vermont Gas's payroll calculations do not appropriately account for expected vacancies and attrition. The Department states that Vermont Gas's calculations account for vacancies due to new employees who were not employed for the full year, but do not account for vacancies that remained at the end of the year due to employees who left. This amounts to 13 positions that were filled during the year and 11 positions that were unfilled at the end of the year due to the departure of an existing employee.[20] According to the Department, Vermont Gas is only accounting for vacancies related to the 13 new employees when projecting Rate Year expenses, when it should also be accounting for the vacancies related to the 11 departures, for a total of 24 positions that experienced vacancies.

Vermont Gas explains that it is accounting for vacancies associated with both new employees and employees who have left Vermont Gas. Vermont Gas explains that the positions held by 13 new and 11 departing employees overlap and that some of the 13 new employees replaced some of 11 departing employees in the same position. The result is a position that was filled at the beginning of the year, had a temporary vacancy during the year, and then was filled with a new employee at the end of the year. Vermont Gas explains that its payroll numbers account for the temporary vacancies that occurred in a position during the year.

We accept Vermont Gas's explanation and conclude that its methodology is a reasonable way to account for expected vacancies. Vermont Gas's calculation of expected vacancies reflects actual vacancies within a position. The Department's proposed reduction of certain payroll expenses by 50% assumes that each of the 24 vacancies occurred in separate positions, and would overstate Vermont Gas's actual vacancy factor. We adopt Vermont Gas's payroll numbers as a more accurate estimate of expected vacancies and employee attrition.

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[20] Wheeler pf. at 10.

D. Rate Base

1. Contingencies

40. Vermont Gas proposes to include $4,533,717 for its Consumer Information System ("CIS") upgrade in rate base, which includes $1,058,402 in project contingencies. Wheeler pf. at 18.

41. Vermont Gas does not generally include contingency forecasts in its rate request. John St. Hilaire, Vermont Gas ("St. Hilaire") pf. reb. at 10.

42. Vermont Gas is not certain that the contingency costs will be 20%, but maintains that 20% is a reasonably accurate prediction. St. Hilaire pf. reb. at 11.

Discussion

The Department opposes Vermont Gas's proposed inclusion of project contingencies in rate base. The Department acknowledges that contingency planning is necessary for project budgeting, but does not agree that contingencies, which represents potential costs that are not known and measurable, should be recovered before they are incurred.

At the evidentiary hearing, Vermont Gas's witness explained that Vermont Gas "wanted to show there is risk associated with this project and that there's a lot of unknown."[21] He further stated: "I can't tell you exactly what those costs are going to be, but we fully expect that what we showed for the budget that there are risks that can impact that budget."[22] Vermont Gas did not address the issue of the contingency in its post-hearing briefing.

We agree with the Department that the $1,058,402 contingency amount included in the budget for CIS upgrades should not be included in rate base. We recognize, however, that including contingencies are a part of sound project planning practices and that Vermont Gas may decide to seek recovery of contingency costs associated with the CIS upgrade in future rate proceedings.

[21] Tr (9/9/19). at 10–11 (St. Hilaire).
[22] *Id.*

2. Construction Work in Progress ("CWIP")

43. Vermont Gas has included the following seven CWIP balances in its rate base even though they will not be completed during the Rate Year: (1) Catamount Gate Station; (2) Quail Hollow Gate Station; (3) Monkton Gate Station; (4) Bristol Distribution System; (5) Monkton Distribution System; (6) St. George Distribution System; and (7) Misc. Wheeler pf. at 20; Simollardes pf. reb. at 21.

44. The parties agree that the CWIP balances that would remain if the seven projects in dispute are removed is $2,116,063. Tr. 9/9/19 at 141 (Wheeler); exh. VGS-Cross 3.

Discussion

The Department recommends that the Commission reduce Vermont Gas's proposed CWIP recovery from $3,131,242 to $2,116,063 by excluding seven capital projects that will not be completed during the Rate Year. The Department states that projects that will not be completed during the Rate Year will not be known and measurable or used and useful and should not be included in rates.

Vermont Gas explains that if the CWIP balance is included in rates now, even though the projects will not be completed within the Rate Year, Vermont Gas will not have to account for the costs as an allowance for funds used during construction ("AFUDC"). Vermont Gas explains that treating the costs as an AFUDC is more expensive than allowing recovery of the CWIP balances now because the interest will be capitalized and become a permanent part of the rate base.

Capital additions to rate base must satisfy the known and measurable standard. To be known and measurable, the addition must be "measurable with a reasonable degree of accuracy and have a high probability of being in effect in the adjusted test year."[23] Here, Vermont Gas admits that the seven projects will not be in service in the Rate Year. We therefore decline to include the projects and direct Vermont Gas to reduce the CWIP balance for inclusion in this rate base to the agreed amount of $2,116,063.

[23] *In re Green Mountain Power Corp.*, 162 Vt. 378, 381 (1994).

E. <u>Disclosure and Reporting Requirements</u>

The Department has recommended several information disclosure and reporting requirements related to Vermont Gas's untariffed services and certain cost-of-service expenses, including staffing and inspection initiatives. At the evidentiary hearing, Vermont Gas agreed to provide the recommended information and reports.[24] We therefore require Vermont Gas to:

- Maintain on its website a list of all untariffed services that it offers to customers together with current pricing information;
- Provide a list of untariffed services offered to customers and updated pricing information through bill inserts when pricing changes;
- On or before December 31 of each year, submit a notice filing to the Commission and the Department that includes: (1) a list of all programs and services offered by VGS that are not subject to a tariff but have costs and revenues included in Vermont Gas's regulated cost of service; (2) the current price charged to customers for each service; and (3) a description of how Vermont Gas determined the appropriate charge for each service;
- Within six months and at the conclusion of the rate year, submit a status update on the in-line inspection program, including: (1) a description of all work completed to date; (2) actual expenses incurred; and (3) a detailed explanation of any unexpected cost-overruns or project delays;
- Within six months and at the conclusion of the rate year, submit a status update on the cross-bore inspection program, including: (1) a description of all work completed to date (including the total number of cross-bore inspections completed); (2) actual expenses incurred; and (3) a detailed explanation of any unexpected cost-overruns or project delays; and
- Provide quarterly notice filings to the Commission and Department on the status of filling the four new employee positions included in this rate filing (GIS Technician; Safety & Compliance Technician; Information Technology; and Field Service Technician) until such time as all four positions have been filled.

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[24] Tr. 9/9/19 at 65, 80-81 (Simollardes); prefiled reb. testimony of Sean Foley ("Foley") at 3; Wheeler pf. sur. at 7, 12.

V. CONCLUSION

Based on the evidence presented in this proceeding, and for the reasons discussed in this Order, we determine that Vermont Gas's requested rate increase should be revised to reflect a 9.2% return on equity, an 8% short-term debt ratio, and adjustments to Vermont Gas's cost of service and rate base as discussed above, with Vermont Gas's requested SERF withdrawal adjusted to maintain an overall increase in non-gas rates of 5% effective for bills rendered on or after November 1, 2019. Vermont Gas's natural gas charges will continue to be established under the alternative regulation plan, as recently extended through September 2020 in Case No. 19-2932-PET.

VI. ORDER

IT IS HEREBY ORDERED, ADJUDGED, AND DECREED by the Public Utility Commission ("Commission") of the State of Vermont that:

1. Vermont Gas Systems, Inc. ("Vermont Gas") may implement a rate increase of 5% in daily access and distribution charges ("non-gas rates") consistent with this Order effective for bills rendered on or after November 1, 2019.

2. During the rate year, Vermont Gas is authorized to withdraw from the System Expansion and Reliability Fund ("SERF") the amount necessary to achieve a 5% rate increase consistent with this Order.

3. Within three business days of issuance of this Order, Vermont Gas shall file a compliance filing including a revised cost of service, calculating the precise amount of SERF withdrawal authorized by this decision.

4. Within three business days of issuance of this Order, Vermont Gas shall file compliance tariffs reflecting the substance of this Order.

5. Vermont Gas shall comply with the information disclosure and reporting obligations described above.

Dated at Montpelier, Vermont, this 23rd day of October, 2019.

Anthony Z. Roisman	)	PUBLIC UTILITY
	)	
	)	
Margaret Cheney	)	COMMISSION
	)	
	)	OF VERMONT
	)	
Sarah Hofmann	)	

OFFICE OF THE CLERK

Filed: October 23, 2019

Attest: Judith C. Whitney
Clerk of the Commission

Notice to Readers: This decision is subject to revision of technical errors. Readers are requested to notify the Clerk of the Commission (by e-mail, telephone, or in writing) of any apparent errors, in order that any necessary corrections may be made. (E-mail address: puc.clerk@vermont.gov)

Appeal of this decision to the Supreme Court of Vermont must be filed with the Clerk of the Commission within 30 days. Appeal will not stay the effect of this Order, absent further order by this Commission or appropriate action by the Supreme Court of Vermont. Motions for reconsideration or stay, if any, must be filed with the Clerk of the Commission within 28 days of the date of this decision and Order.

PUC Case No. 19-0513-TF - SERVICE LIST

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Edison Electric INSTITUTE

Dividends

Q3 2019
FINANCIAL UPDATE

QUARTERLY REPORT
OF THE U.S. INVESTOR-OWNED
ELECTRIC UTILITY INDUSTRY

About EEI

EEI is the association that represents all U.S. investor-owned electric companies. Our members provide electricity for 220 million Americans, and operate in all 50 states and the District of Columbia. As a whole, the electric power industry supports more than 7 million jobs in communities across the United States. In addition to our U.S. members, EEI has more than 60 international electric companies, with operations in more than 90 countries, as International Members, and hundreds of industry suppliers and related organizations as Associate Members. Organized in 1933, EEI provides public policy leadership, strategic business intelligence, and essential conferences and forums.

About EEI's Quarterly Financial Updates

EEI's quarterly regulatory and financial updates present industry trend analyses and financial data covering 45 U.S. investor-owned electric utility companies. These 45 companies include 40 electric utility holding companies whose stocks are traded on major U.S. stock exchanges and five electric utilities who are subsidiaries of non-utility or foreign companies. Financial updates are published for the following topics:

- Stock Performance
- Dividends
- Credit Ratings
- Rate Review Summary

EEI Finance Department material can be found online at: www.eei.org/QFU.

For EEI Member Companies

The EEI Finance and Accounting Division maintains current year and historical data sets that cover a wide range of industry financial and operating metrics. We look forward to serving as a resource for member companies who wish to produce customized industry financial data and trend analyses for use in:

- Investor relations studies and presentations
- Internal company presentations
- Performance benchmarking
- Peer group analyses
- Annual and quarterly reports to shareholders

We Welcome Your Feedback

EEI is interested in ensuring that our publications and industry data sets best address the needs of member companies and the regulatory and financial communities. We welcome your comments, suggestions and inquiries.

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Future EEI Finance Meetings

EEI Wall Street Briefing
February 5, 2020
University Club
New York, New York

EEI Financial Officers' Meeting
June 9-10, 2020
JW Marriott Austin
Austin, Texas

EEI Financial Conference
November 8-10, 2020
JW Marriott Desert Ridge Resort and Spa
Phoenix, Arizona

For more information about future EEI Finance Meetings, please contact Devin James at (202) 508-5057 or djames@eei.org, or Aaron Cope, Jr. at (202) 508-5128 or acope@eei.org.

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The 45 U.S. Investor-Owned Electric Utilities

The companies listed below all serve a regulated distribution territory. Other utilities, such as transmission provider ITC Holdings, are not shown below because they do not serve a regulated distribution territory. However, their financial information is included in relevant EEI data sets, such as transmission-related construction spending.

ALLETE, Inc. (ALE)
Alliant Energy Corporation (LNT)
Ameren Corporation (AEE)
American Electric Power Company, Inc. (AEP)
AVANGRID, Inc. (AGR)
Avista Corporation (AVA)
Berkshire Hathaway Energy
Black Hills Corporation (BKH)
CenterPoint Energy, Inc. (CNP)
Cleco Corporation
CMS Energy Corporation (CMS)
Consolidated Edison, Inc. (ED)
Dominion Resources, Inc. (D)
DPL, Inc.
DTE Energy Company (DTE)
Duke Energy Corporation (DUK)
Edison International (EIX)
El Paso Electric Company (EE)
Entergy Corporation (ETR)
Evergy, Inc. (EVRG)
Eversource Energy (ES)
Exelon Corporation (EXC)
FirstEnergy Corp. (FE)
Hawaiian Electric Industries, Inc. (HE)
IDACORP, Inc. (IDA)
IPALCO Enterprises, Inc.
MDU Resources Group, Inc. (MDU)
MGE Energy, Inc. (MGEE)
NextEra Energy, Inc. (NEE)
NiSource Inc. (NI)
NorthWestern Corporation (NWE)
OGE Energy Corp. (OGE)
Otter Tail Corporation (OTTR)
PG&E Corporation (PCG)
Pinnacle West Capital Corporation (PNW)
PNM Resources, Inc. (PNM)
Portland General Electric Company (POR)
PPL Corporation (PPL)
Public Service Enterprise Group Inc. (PEG)
Puget Energy, Inc.
Sempra Energy (SRE)
Southern Company (SO)
Unitil Corporation (UTL)
WEC Energy Group, Inc. (WEC)
Xcel Energy, Inc. (XEL)

Note: Companies shown in italics are not listed on U.S. stock exchanges for one of the following reasons — they are subsidiaries of an independent power producer; they are subsidiaries of foreign-owned companies; or they were acquired by other investment firms.

Companies Listed by Category
(Based on Business Segmentation Data as of 12/31/2018)

Please refer to the Quarterly Financial Updates webpage for previous years' lists.

Given the diversity of utility holding company corporate strategies, no single company categorization approach will be useful for all EEI members and utility industry analysts. Nevertheless, we believe the following classification provides an informative framework for tracking financial trends and the capital markets' response to business strategies as companies depart from the traditional regulated utility model.

Regulated	80% or more of total assets are regulated
Mostly Regulated	Less than 80% of total assets are regulated

Categorization is based on year-end business segmentation data presented in SEC 10-K filings, supplemented by discussions with and information provided by parent company IR departments.

The EEI Finance and Accounting Division continues to evaluate our approach to company categorization and business segmentation. In addition, we can produce customized categorization and peer group analyses in response to member company requests. We welcome comments, suggestions and feedback from EEI member companies and the financial community.

Regulated (35 of 45)

Alliant Energy Corporation
Ameren Corporation
American Electric Power Company, Inc.
Avista Corporation
Black Hills Corporation
Cleco Corporation
CMS Energy Corporation
Consolidated Edison, Inc.
Dominion Resources, Inc.
DPL Inc.
Duke Energy Corporation
Edison International
El Paso Electric Company
Entergy Corporation
Evergy, Inc.
Eversource Energy
FirstEnergy Corp.
IDACORP, Inc.
IPALCO Enterprises, Inc.
MGE Energy, Inc.
NiSource Inc.
NorthWestern Corporation
OGE Energy Corp.
Otter Tail Corporation
PG&E Corporation
Pinnacle West Capital Corporation
PNM Resources, Inc.
Portland General Electric Company
PPL Corporation
Puget Energy, Inc.
Sempra Energy
Southern Company
Unitil Corporation
WEC Energy Group, Inc.
Xcel Energy Inc.

Mostly Regulated (10 of 45)

ALLETE, Inc.
AVANGRID, Inc.
Berkshire Hathaway Energy
CenterPoint Energy, Inc.
DTE Energy Company
Exelon Corporation
Hawaiian Electric Industries, Inc.
MDU Resources Group, Inc.
NextEra Energy, Inc.
Public Service Enterprise Group Incorporated

Note: Companies shown in italics are not listed on U.S. stock exchanges for one of the following reasons — they are subsidiaries of an independent power producer; they are subsidiaries of foreign-owned companies; or they were acquired by other investment firms.

Q3 2019

Dividends

HIGHLIGHTS

- The investor-owned electric utility industry continued its long-term trend of widespread dividend increases during the first nine months of 2019; 23 companies increased or reinstated their dividend compared to 25 in the same 2018 period.
- The percentage of companies that raised or reinstated their dividend in calendar year 2018 was 93%, a new record high. This exceeded 2017's 88% and the previous record of 91% in 2016.
- The average dividend increase during the first nine months of 2019 was 5.0%, with a range of 0.6% to 12.6% and a median increase of 4.7%.
- The industry's dividend payout ratio was 69.3% for the twelve months ended June 30, 2019, trailing only the Energy sector's 73.3% among all U.S. business sectors.
- The industry's average dividend yield was 2.9% on September 30, 2019, down from 3.4% at yearend 2018. The EEI Index gained more than 25% during the first nine months of 2019, offsetting the widespread dividend growth and resulting in a slightly lower yield.

COMMENTARY

The investor-owned electric utility industry continued its long-term trend of widespread dividend increases during the first nine months of 2019. A total of 23 companies increased or reinstated their dividend compared to 25 during the same period of 2018. On a calendar year basis, 39 companies increased their dividend in 2018 compared to 38 in 2017, 40 in 2016, 39 in 2015, 38 in 2014 and 36 in both 2013 and 2012.

The percentage of companies that raised or reinstated their dividend in calendar year 2018 was 93%, a new record high. This exceeded 2017's 88% and the previous record of

I. Sector Comparison, Dividend Payout Ratio

Last Twelve Months

Sector	Payout Ratio (%)
EEI Index Companies*	69.3%
Energy	73.3%
Utilities	63.8%
Consumer Staples	57.0%
Materials	40.7%
Industrial	35.4%
Consumer Discretionary	30.7%
Technology	30.2%
Health Care	27.9%
Financial	27.2%

*For this table, EEI (1) sums dividends and (2) sums earnings of all index companies and then (3) divides to determine the comparable dividend payout ratio (DPR).

EEI Index Companies payout ratio based on LTM common dividends paid and income before nonrecurring and extraordinary items.

S&P sector payout ratios based on 2019E dividends and earnings per share (estimates as of 9/30/2019).

For more information on constituents of each S&P sector see www.sectorspdr.com.

Source: AltaVista Research, S&P Global Market Intelligence, EEI Finance Department

II. Sector Comparison, Dividend Yield

at 12/31/2018

Sector	Yield (%)
EEI Index Companies	2.9%
Energy	3.9%
Utilities	3.1%
Consumer Staples	2.8%
Financial	2.2%
Materials	2.1%
Industrial	2.0%
Health Care	1.8%
Consumer Discretionary	1.4%
Technology	1.4%

*EEI Index Companies' yield based on last announced, annualized dividend rates (as of 9/30/2019); S&P sector yields based on 2019E cash dividends (estimates as of 9/30/2019).

For more information on constituents of each S&P sector see www.sectorspdr.com.

Source: AltaVista Research, S&P Global Market Intelligence, EEI Finance Department

III. Dividend Patterns 1994–2019

U.S. Investor-Owned Electric Utilities

	Raised	No Change	Lowered	Omitted	Reinstated	Not Paying	Total	Dividend Payout Ratio*
1994	54	37	6	0	0	3	100	79.8%
1995	52	40	3	0	0	3	98	75.3%
1996	48	44	2	1	1	2	98	70.7%
1997	40	45	6	2	0	3	96	84.2%
1998	40	37	7	0	0	5	89	82.1%
1999	29	45	4	0	3	2	83	74.9%
2000	26	39	3	1	0	2	71	63.9%
2001	21	40	3	2	0	3	69	64.1%
2002	26	27	6	3	0	3	65	67.5%
2003	26	24	7	2	1	5	65	63.7%
2004	35	22	1	0	0	7	65	67.9%
2005	34	22	1	1	2	5	65	66.5%
2006	41	17	0	0	0	6	64	63.5%
2007	40	15	0	0	3	3	61	62.1%
2008	36	20	1	0	1	1	59	66.8%
2009	31	23	3	0	0	1	58	69.6%
2010	34	22	0	0	0	1	57	62.0%
2011	31	22	0	1	1	0	55	62.8%
2012	36	14	0	0	1	0	51	64.2%
2013	36	12	1	0	0	0	49	61.5%
2014	38	9	1	0	0	0	48	60.4%
2015	39	7	0	0	0	0	46	67.0%
2016	40	4	0	0	0	0	44	62.9%
2017	38	4	0	1	0	0	43	64.0%
2018	39	1	1	0	0	1	42	63.9%
2019 Q1	17	22	0	0	0	1	40	65.6%
2019 Q2	3	36	0	0	0	1	40	68.8%
2019 Q2	3	36	0	0	0	1	40	68.7%

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019 Q1	2019 Q2	2019 Q3
Avg. Increase	18.7%	8.4%	9.2%	7.4%	9.4%	7.2%	8.2%	6.8%	7.2%	5.3%	5.7%	5.8%	5.6%	5.6%	5.7%	5.0%	5.5%	4.2%
Avg. Decrease	47.4%	40.0%	NA	NA	45.7%	46.4%	NA	100%	NA	41.0%	34.5%	NA	NA	NA	79.8%	NA	NA	NA

Note: Prior to 2000: Total industry dividends/total industry earnings. Starting in 2000: Average of all companies paying dividend. Only one action per company per year is counted. If a company raised its dividend twice, this counts as one in the Raised column. / * Current year figures reflect dividend changes (raised, lowered, etc.) through 9/30/2019 and earnings and dividends through 6/30/2019 (payout ratio). / Source: AltaVista Research, S&P Global Market Intelligence, EEI Finance Department

IV. Category Comparison, Dividend Payout Ratio

Last Twelve Months

Category	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
EEI Index	62.0	62.8	64.2	61.5	60.4	67.0	62.9	64.0	63.9	68.7
Regulated	64.1	63.4	62.1	60.5	59.4	68.7	61.1	68.7	60.1	69.1
Mostly Reg.	60.7	63.1	69.7	64.7	63.8	62.6	68.0	53.3	72.8	67.2
Diversified	49.7	54.7	53.4	44.7	56.4	64.9	64.6	--	--	--

Regulated: 80% or more of total assets are regulated
Mostly Regulated: Less than 80% of total assets are regulated
Diversified: Prior to 2017, less than 50% of total assets are regulated
*2019 figures reflect earnings and dividends through 6/30/2019.
Source: EEI Finance Department, S&P Global Market Intelligence and company reports.

V. Category Comparison, Dividend Yield

at 9/30/2019

Category	Dividend Yield (%)
EEI Index	2.9
Regulated	2.9
Mostly Regulated	3.0

Regulated: 80% or more of total assets are regulated
Mostly Regulated: Less than 80% of total assets are regulated
Source: EEI Finance Department, S&P Global Market Intelligence and company reports.

91% in 2016, the next two highest historical results. Both totals followed results of 85% in 2015 and a range of 73% to 79% going back to 2012. By comparison, in 2003 (just prior to the passage of legislation that reduced dividend tax rates) only 27 of the 65 utilities tracked by EEI increased their dividend. (Note: M&A activity reduced the number of utilities tracked by EEI from 65 in 2003 to 42 at year end 2018). The 2018 record high is based on data beginning in 1988.

As shown in Table III – Dividend Patterns, 39 of the 40 publicly traded utilities in the EEI Index were paying a common stock dividend as of September 30. Each company is limited to one action per year in the table; if a company raised its dividend twice in a year, that counts as one in the Raised column. Companies generally use the same quarter each year for dividend changes, with the first quarter being the most common for electric utilities.

VI. Dividend Summary

U.S. Investor-Owned Electric Utilities (at 9/30/2019)

Company (Stock Symbol)	Company Category	Annualized Dividend	Payout Ratio (%)	Yield (%)	Last Action	To	From	Date Announced
ALLETE, Inc. (ALE)	MR	$2.35	67.3%	2.7%	Raised	$2.35	$2.24	2019 Q1
Alliant Energy Corporation (LNT)	R	$1.42	62.5%	2.6%	Raised	$1.42	$1.34	2019 Q1
Ameren Corporation (AEE)	R	$1.90	57.6%	2.4%	Raised	$1.90	$1.83	2018 Q4
American Electric Power Co., Inc. (AEP)	R	$2.68	63.9%	2.9%	Raised	$2.68	$2.48	2018 Q4
AVANGRID, Inc. (AGR)	MR	$1.76	94.8%	3.4%	Raised	$1.76	$1.73	2018 Q3
Avista Corporation (AVA)	R	$1.55	86.6%	3.2%	Raised	$1.55	$1.49	2019 Q1
Black Hills Corporation (BKH)	R	$2.02	48.9%	2.6%	Raised	$2.02	$1.90	2018 Q4
CenterPoint Energy, Inc (CNP)	MR	$1.15	68.6%	3.8%	Raised	$1.15	$1.11	2018 Q4
CMS Energy Corporation (CMS)	R	$1.53	70.0%	2.4%	Raised	$1.53	$1.43	2019 Q1
Consolidated Edison, Inc. (ED)	R	$2.96	69.7%	3.1%	Raised	$2.96	$2.86	2019 Q1
Dominion Energy, Inc. (D)	R	$3.67	130.2%	4.5%	Raised	$3.67	$3.34	2018 Q4
DTE Energy Company (DTE)	MR	$3.78	56.6%	2.8%	Raised	$3.78	$3.53	2018 Q4
Duke Energy Corporation (DUK)	R	$3.78	65.8%	3.9%	Raised	$3.78	$3.71	2019 Q3
Edison International (EIX)	R	$2.45	29.6%	3.2%	Raised	$2.45	$2.42	2018 Q4
El Paso Electric Company (EE)	R	$1.54	62.2%	2.3%	Raised	$1.54	$1.44	2019 Q2
Entergy Corporation (ETR)	R	$3.64	46.1%	3.1%	Raised	$3.64	$3.56	2018 Q4
Evergy, Inc. (EVRG)	R	$1.90	73.4%	2.9%	Raised	$1.90	$1.84	2018 Q4
Eversource Energy (ES)	R	$2.14	58.1%	2.5%	Raised	$2.14	$2.02	2019 Q1
Exelon Corporation (EXC)	MR	$1.45	57.5%	3.0%	Raised	$1.45	$1.38	2019 Q1
FirstEnergy Corp. (FE)	R	$1.52	60.9%	3.2%	Raised	$1.52	$1.44	2018 Q4
Hawaiian Electric Industries, Inc. (HE)	MR	$1.28	66.8%	2.8%	Raised	$1.28	$1.24	2019 Q1
IDACORP, Inc. (IDA)	R	$2.52	55.8%	2.2%	Raised	$2.52	$2.36	2018 Q3
MDU Resources Group, Inc. (MDU)	MR	$0.81	54.6%	2.9%	Raised	$0.81	$0.79	2018 Q4
MGE Energy, Inc. (MGEE)	R	$1.41	54.8%	1.8%	Raised	$1.41	$1.35	2019 Q3
NextEra Energy, Inc. (NEE)	MR	$5.00	87.1%	2.1%	Raised	$5.00	$4.44	2019 Q1
NiSource Inc. (NI)	R	$0.80	145.9%	2.7%	Raised	$0.80	$0.78	2019 Q1
NorthWestern Corporation (NWE)	R	$2.30	52.3%	3.1%	Raised	$2.30	$2.20	2019 Q1
OGE Energy Corp. (OGE)	R	$1.55	70.7%	3.4%	Raised	$1.55	$1.46	2019 Q3
Otter Tail Corporation (OTTR)	R	$1.40	68.8%	2.6%	Raised	$1.40	$1.34	2019 Q1
PG&E Corporation (PCG)	R	$0.00	0.0%	0.0%	Lowered	$0.00	$2.12	2017 Q4
Pinnacle West Capital Corporation (PNW)	R	$2.95	61.0%	3.0%	Raised	$2.95	$2.78	2018 Q4
PNM Resources, Inc. (PNM)	R	$1.16	43.4%	2.2%	Raised	$1.16	$1.06	2018 Q4
Portland General Electric Company (POR)	R	$1.54	64.5%	2.7%	Raised	$1.54	$1.45	2019 Q2
PPL Corporation (PPL)	R	$1.65	66.2%	5.2%	Raised	$1.65	$1.64	2019 Q1
Public Service Enterprise Group Inc. (PEG)	MR	$1.88	51.5%	3.0%	Raised	$1.88	$1.80	2019 Q1
Sempra Energy (SRE)	R	$3.87	66.3%	2.6%	Raised	$3.87	$3.58	2019 Q1
Southern Company (SO)	R	$2.48	141.2%	4.0%	Raised	$2.48	$2.40	2019 Q2
Unitil Corporation (UTL)	R	$1.48	70.9%	2.3%	Raised	$1.48	$1.46	2019 Q1
WEC Energy Group, Inc. (WEC)	R	$2.36	65.8%	2.5%	Raised	$2.36	$2.21	2018 Q4
Xcel Energy Inc. (XEL)	R	$1.62	60.3%	2.5%	Raised	$1.62	$1.52	2019 Q1
Industry Average			**68.7%**	**2.9%**				

Categories — R = Regulated (80% or more of total assets are regulated), MR = Mostly Regulated (Less than 80% of total assets are regulated); based on assets at 12/31/2018.
Dividend Per Share — Per share amounts are annualized declared figures as of 9/30/2019.
Dividend Payout Ratio — Dividends paid for 12 months ended 6/30/2019 divided by net income before nonrecurring and extraordinary items for 12 months ended 6/30/2019.
Dividend Yield — Annualized Dividends Per Share at 9/30/2019 divided by stock price at market close on 9/30/2019.
NM applies to companies with negative earnings or payout ratios greater than 200%.

While net income is after-tax, nonrecurring and extraordinary items are pre-tax, as there is no consistent method of gathering these items on a tax adjusted basis under current reporting guidelines. On an individual company basis, the Payout Ratio in the table could differ slightly from what is reported directly by the company.

Source: EEI Finance Department and S&P Global Market Intelligence

VII. Free Cash Flow

U.S. Investor-Owned Electric Utilities

($ Billions)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Net Cash Provided by Oper. Activities	82.9	77.7	84.4	84.0	87.1	89.0	101.6	98.3	101.2	100.0
— Capital Expenditures	(77.6)	(74.2)	(78.6)	(90.3)	(90.3)	(96.1)	(104.0)	(112.5)	(113.1)	(119.5)
— Div. Paid to Common Shareholders	(17.1)	(18.0)	(19.3)	(20.5)	(20.8)	(21.1)	(22.5)	(23.8)	(25.5)	(25.6)
Free Cash Flow	(11.8)	(14.4)	(13.5)	(26.8)	(24.0)	(28.2)	(24.8)	(38.0)	(37.5)	(37.5)

Source: S&P Global Market Intelligence and EEI Finance Department

2019 Increases Average 5.0%

The average dividend increase during the first nine months of 2019 was 5.0%, with a range of 0.6% to 12.6% and a median increase of 4.7%. NextEra Energy (+12.6% in Q1), Sempra Energy (+8.1% in Q1) and CMS Energy (+7.0% in Q1) posted the largest percentage increases.

NextEra Energy, headquartered in Juno Beach, Florida, raised its quarterly dividend from $1.11 to $1.25 per share in Q1. The increase was consistent with the company's plan, announced in 2018, to target 12% to 14% annual per-share dividend growth through at least 2020. NextEra recorded the industry's second-highest percentage increase in 2018 (+13.0%), and the highest in both 2017 (+12.9%) and 2016 (+13.0%, along with Edison International and DTE Energy).

Sempra Energy, based in San Diego, California, announced in Q1 a quarterly increase from $0.895 to $0.9675 per share. This marks the ninth consecutive year that Sempra has increased its common stock dividend, which has grown by more than 47 percent since 2014.

CMS Energy, headquartered in Jackson, Michigan, increased its quarterly dividend from $0.3575 to $0.3825 per share during Q1.

Payout Ratio and Dividend Yield

The industry's dividend payout ratio was 69.3% for the twelve months ended June 30, 2019, trailing only the Energy sector's 73.3% among U.S. business sectors. The industry's payout ratio was 68.7% when measured as an unweighted average of individual company ratios; 69.3% represents an aggregate figure. From 2000 through 2018, the industry's annual payout ratio ranged from 60.4% to 69.6%.

While the industry's net income has fluctuated from year to year, its payout ratio has remained relatively consistent after eliminating non-recurring and extraordinary items from earnings. We use the following approach when calculating the industry's dividend payout ratio:

1. Non-recurring and extraordinary items are eliminated from earnings.
2. Companies with negative adjusted earnings are eliminated.
3. Companies with a payout ratio in excess of 200% are eliminated.

The industry's average dividend yield was 2.9% on September 30, 2019, trailing only the Energy sector's 3.7% and the broader Utilities sector's 3.5%. The industry's 2018 year-end yield was a slightly higher 3.4% (for a third consecutive year). The market cap-weighted EEI Index increased by more than 25% during the first nine months of 2019, offsetting the period's dividend growth and resulting in the slightly lower yield.

We calculate the industry's aggregate dividend yield using an unweighted average of the yields of EEI Index companies that are paying a dividend. The strong yields prevalent among most electric utilities have supported their share prices over the past decade, especially given the period's historically low interest rates. The Tax Cuts and Jobs Act signed into law in December 2017 maintained pre-existing tax rates for dividends and capital gains. This is crucial to avoid a capital raising disadvantage for high-dividend companies.

Business Category Comparison

The Regulated company category had a dividend payout ratio of 69.1% for the 12 months ended June 30, 2019 compared to 67.2% for the Mostly Regulated group. The Regulated category produced the highest annual payout ratio in 2017, 2015, 2011 and 2010 and in each year from 2003 through 2008. It was exceeded by the Mostly Regulated category in 2018, 2016, 2014, 2013, 2012 and 2009. It's likely that the weaker earnings from the competitive power business contributed to the higher payout ratio among Mostly Regulated companies in those years.

The Regulated and Mostly Regulated groups had average dividend yields of 2.9% and 3.0%, respectively, as of September 30, 2019. Both groups had a 3.4% average dividend yield at year-end 2018, mirroring their yields at year-end 2017. The yields for the Regulated and Mostly Regulated categories were 3.4% and 3.5%, respectively, on December 31, 2016..■

Edison Electric
INSTITUTE

Stock Performance

Q3 2019
FINANCIAL UPDATE

QUARTERLY REPORT
OF THE U.S. INVESTOR-OWNED
ELECTRIC UTILITY INDUSTRY

About EEI

EEI is the association that represents all U.S. investor-owned electric companies. Our members provide electricity for 220 million Americans, and operate in all 50 states and the District of Columbia. As a whole, the electric power industry supports more than 7 million jobs in communities across the United States. In addition to our U.S. members, EEI has more than 60 international electric companies, with operations in more than 90 countries, as International Members, and hundreds of industry suppliers and related organizations as Associate Members. Organized in 1933, EEI provides public policy leadership, strategic business intelligence, and essential conferences and forums.

About EEI's Quarterly Financial Updates

EEI's quarterly regulatory and financial updates present industry trend analyses and financial data covering 45 U.S. investor-owned electric utility companies. These 45 companies include 40 electric utility holding companies whose stocks are traded on major U.S. stock exchanges and five electric utilities who are subsidiaries of non-utility or foreign companies. Financial updates are published for the following topics:

- Stock Performance
- Dividends
- Credit Ratings
- Rate Review Summary

EEI Finance Department material can be found online at: www.eei.org/QFU.

For EEI Member Companies

The EEI Finance and Accounting Division maintains current year and historical data sets that cover a wide range of industry financial and operating metrics. We look forward to serving as a resource for member companies who wish to produce customized industry financial data and trend analyses for use in:

- Investor relations studies and presentations
- Internal company presentations
- Performance benchmarking
- Peer group analyses
- Annual and quarterly reports to shareholders

We Welcome Your Feedback

EEI is interested in ensuring that our publications and industry data sets best address the needs of member companies and the regulatory and financial communities. We welcome your comments, suggestions and inquiries.

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Future EEI Finance Meetings

EEI Wall Street Briefing
February 5, 2020
University Club
New York, New York

EEI Financial Officers' Meeting
June 9-10, 2020
JW Marriott Austin
Austin, Texas

EEI Financial Conference
November 8-10, 2020
JW Marriott Desert Ridge Resort and Spa
Phoenix, Arizona

For more information about future EEI Finance Meetings, please contact Devin James at (202) 508-5057 or djames@eei.org, or Aaron Cope, Jr. at (202) 508-5128 or acope@eei.org.

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The 45 U.S. Investor-Owned Electric Utilities

The companies listed below all serve a regulated distribution territory. Other utilities, such as transmission provider ITC Holdings, are not shown below because they do not serve a regulated distribution territory. However, their financial information is included in relevant EEI data sets, such as transmission-related construction spending.

ALLETE, Inc. (ALE)
Alliant Energy Corporation (LNT)
Ameren Corporation (AEE)
American Electric Power Company, Inc. (AEP)
AVANGRID, Inc. (AGR)
Avista Corporation (AVA)
Berkshire Hathaway Energy
Black Hills Corporation (BKH)
CenterPoint Energy, Inc. (CNP)
Cleco Corporation
CMS Energy Corporation (CMS)
Consolidated Edison, Inc. (ED)
Dominion Resources, Inc. (D)
DPL, Inc.
DTE Energy Company (DTE)
Duke Energy Corporation (DUK)
Edison International (EIX)
El Paso Electric Company (EE)
Entergy Corporation (ETR)
Evergy, Inc. (EVRG)
Eversource Energy (ES)
Exelon Corporation (EXC)
FirstEnergy Corp. (FE)
Hawaiian Electric Industries, Inc. (HE)
IDACORP, Inc. (IDA)
IPALCO Enterprises, Inc.
MDU Resources Group, Inc. (MDU)
MGE Energy, Inc. (MGEE)
NextEra Energy, Inc. (NEE)
NiSource Inc. (NI)
NorthWestern Corporation (NWE)
OGE Energy Corp. (OGE)
Otter Tail Corporation (OTTR)
PG&E Corporation (PCG)
Pinnacle West Capital Corporation (PNW)
PNM Resources, Inc. (PNM)
Portland General Electric Company (POR)
PPL Corporation (PPL)
Public Service Enterprise Group Inc. (PEG)
Puget Energy, Inc.
Sempra Energy (SRE)
Southern Company (SO)
Unitil Corporation (UTL)
WEC Energy Group, Inc. (WEC)
Xcel Energy, Inc. (XEL)

Note: Companies shown in italics are not listed on U.S. stock exchanges for one of the following reasons — they are subsidiaries of an independent power producer; they are subsidiaries of foreign-owned companies; or they were acquired by other investment firms.

Companies Listed by Category

(Based on Business Segmentation Data as of 12/31/2018)

Please refer to the Quarterly Financial Updates webpage for previous years' lists.

Given the diversity of utility holding company corporate strategies, no single company categorization approach will be useful for all EEI members and utility industry analysts. Nevertheless, we believe the following classification provides an informative framework for tracking financial trends and the capital markets' response to business strategies as companies depart from the traditional regulated utility model.

Regulated	80% or more of total assets are regulated
Mostly Regulated	Less than 80% of total assets are regulated

Categorization is based on year-end business segmentation data presented in SEC 10-K filings, supplemented by discussions with and information provided by parent company IR departments.

The EEI Finance and Accounting Division continues to evaluate our approach to company categorization and business segmentation. In addition, we can produce customized categorization and peer group analyses in response to member company requests. We welcome comments, suggestions and feedback from EEI member companies and the financial community.

Regulated (35 of 45)

Alliant Energy Corporation
Ameren Corporation
American Electric Power Company, Inc.
Avista Corporation
Black Hills Corporation
Cleco Corporation
CMS Energy Corporation
Consolidated Edison, Inc.
Dominion Resources, Inc.
DPL Inc.
Duke Energy Corporation
Edison International
El Paso Electric Company
Entergy Corporation
Evergy, Inc.
Eversource Energy
FirstEnergy Corp.
IDACORP, Inc.
IPALCO Enterprises, Inc.
MGE Energy, Inc.
NiSource Inc.
NorthWestern Corporation
OGE Energy Corp.
Otter Tail Corporation
PG&E Corporation
Pinnacle West Capital Corporation
PNM Resources, Inc.
Portland General Electric Company
PPL Corporation
Puget Energy, Inc.
Sempra Energy
Southern Company
Unitil Corporation
WEC Energy Group, Inc.
Xcel Energy Inc.

Mostly Regulated (10 of 45)

ALLETE, Inc.
AVANGRID, Inc.
Berkshire Hathaway Energy
CenterPoint Energy, Inc.
DTE Energy Company
Exelon Corporation
Hawaiian Electric Industries, Inc.
MDU Resources Group, Inc.
NextEra Energy, Inc.
Public Service Enterprise Group Incorporated

Note: Companies shown in italics are not listed on U.S. stock exchanges for one of the following reasons — they are subsidiaries of an independent power producer; they are subsidiaries of foreign-owned companies; or they were acquired by other investment firms.

Q3 2019

Stock Performance

HIGHLIGHTS

- The EEI Index returned 8.2% in Q3 and 26.6% for the 12-months ending September 30, solidly outperforming the broad market's 2% and 4% gains, respectively, for the same periods. The U.S. Fed cut short-term rates twice during Q3. The 10-year Treasury yield reached a low of 1.5% in early September, down from 3.2% a year earlier.
- Electric output fell 0.6% year-to-year in Q3 after a 4.4% decline in Q2. Analysts cited weather and slowing economic growth while some companies also noted the impact of trade tariffs on industrial demand.
- Industry analysts noted the long-term visibility for industry capex, rate base and earnings growth extended farther during Q3. Investors' search for earnings growth in a low-yield, slow-growth, global economy may drive historically high utility share valuations even higher.
- Stable fuel costs and low interest rates have kept utility bills down even as capex has surged. Pushback on rate increases needed to fund rising capex may become an issue if the economy enters recession and consumer incomes fall.

COMMENTARY

The EEI Index solidly outperformed market averages in Q3, returning 8.2% versus 1.8% for the Dow Jones Industrials, 1.7% for the S&P 500, and -0.1% for the tech-heavy Nasdaq Composite. The broad market's rally paused on fears of slowing economic growth in the U.S. and overseas while falling interest rates, due in part to two Federal Reserve rate cuts during the quarter, powered utility shares higher. The quarter's strength produced a 25.3% total return for the EEI Index

I. Index Comparison (% Return)

Index	2013	2014	2015	2016	2017	2018	9 mo. 2019
EEI Index	13.0	28.9	-3.9	17.4	11.7	3.7	25.3
Dow Jones Inds.	29.6	10.0	0.2	16.5	28.1	-3.5	17.5
S&P 500	32.4	13.7	1.4	12.0	21.8	-4.4	20.6
Nasdaq Comp.^	38.3	13.4	5.7	7.5	28.2	-3.9	20.6

Calendar year returns shown for all periods, except where noted.
^Price gain/loss only. Other indices show total return.
Source: EEI Finance Department, S&P Global Market Intelligence

II. Category Comparison (% Return)

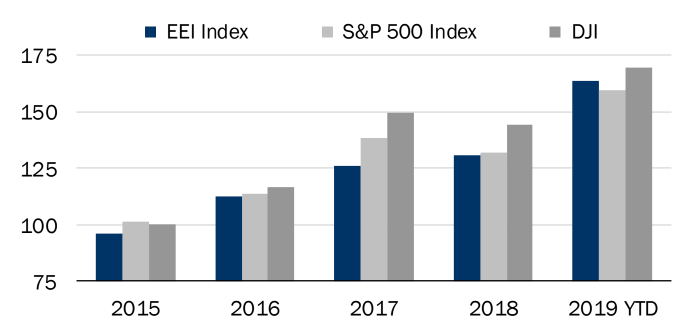
U.S. Investor-Owned Electric Utilities

Index	2013	2014	2015	2016	2017	2018	9 mo. 2019
All Companies	17.3	27.6	-2.0	22.2	11.6	4.3	23.5
Regulated	17.0	28.9	-0.7	21.2	11.7	4.5	24.7
Mostly Regulated	16.0	27.5	-3.7	24.6	11.3	3.6	19.3
Diversified	47.5	6.6	-14.4	25.6	n/a*	n/a*	n/a*

Calendar year returns shown for all periods except where noted.
Returns shown here are unweighted averages of constituent company returns.
The EEI Index return shown in Table I above is cap-weighted.
*Diversified category eliminated in 2017 due to lack of constituent companies.
Source: EEI Finance Department, S&P Global Market Intelligence and company reports

III. Total Return Comparison

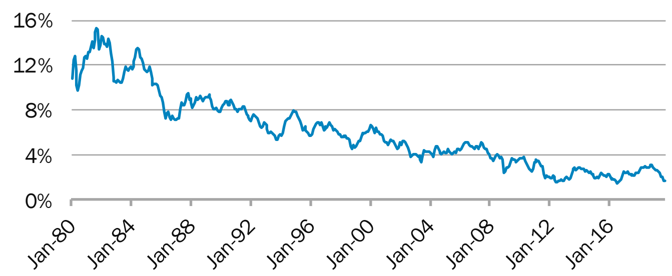
Value of $100 invested at close on 12/31/2014



Source: EEI Finance Department, S&P Global Market Intelligence

IV. 10-Year Treasury Yield — Monthly

Average Monthly Yield, 1/1/1980 through 9/30/2019



Source: U.S. Federal Reserve

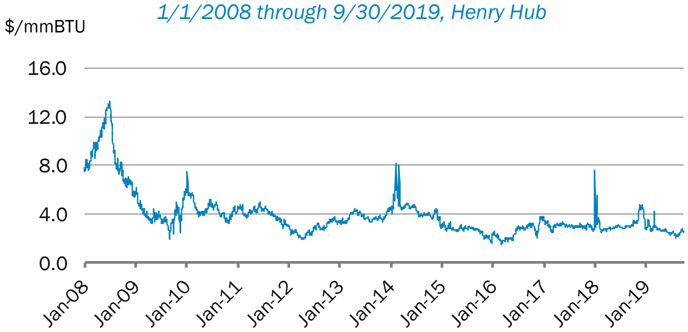
V. 10-Year Treasury Yield — Weekly

Daily Yield, 1/1/2008 through 9/30/2019

Source: U.S. Federal Reserve

VI. Natural Gas Spot Prices

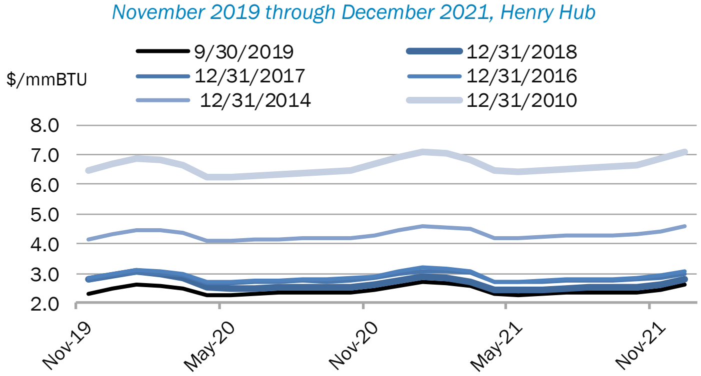
1/1/2008 through 9/30/2019, Henry Hub



Source: S&P Global Market Intelligence

VII. NYMEX Natural Gas Futures

November 2019 through December 2021, Henry Hub



Source: S&P Global Market Intelligence

VIII. Returns by Quarter

U.S. Investor-Owned Electric Utilities

Index	2016 Q4	2017 Q1	2017 Q2	2017 Q3	2017 Q4	2018 Q1	2018 Q2	2018 Q3	2018 Q4	2019 Q1	2019 Q2	2019 Q3
EEI Index	0.5	6.1	2.4	2.7	0.1	-3.3	3.8	2.0	1.3	11.1	4.1	8.2
Dow Jones Industrials	8.7	5.2	4.0	5.3	11.3	-2.0	1.3	9.6	-11.3	11.8	3.2	1.8
S&P 500	3.8	6.1	3.1	4.5	6.6	-0.8	3.4	7.7	-13.5	13.7	4.3	1.7
Nasdaq Comp.^	1.3	9.8	3.9	5.8	6.3	2.3	6.3	7.1	-17.5	16.5	3.6	-0.1

Category*	2016 Q4	2017 Q1	2017 Q2	2017 Q3	2017 Q4	2018 Q1	2018 Q2	2018 Q3	2018 Q4	2019 Q1	2019 Q2	2019 Q3
All Companies	2.7	5.2	2.5	3.2	0.2	-3.0	5.3	1.4	0.8	10.6	4.9	6.5
Regulated	1.9	5.8	2.7	3.5	-0.7	-3.5	5.4	2.0	0.7	10.6	5.9	6.5
Mostly Regulated	3.8	3.9	2.0	2.5	2.5	-1.9	5.0	-0.3	0.9	10.5	1.3	6.6
Diversified	9.5	n/a**	n/a**	n/a**	n/a**	n/a**	n/a**	n/a**	n/a**	n/a**	n/a**	n/a**

^Price gain/(loss) only. Other indices show total return. / * Returns shown here are unweighted averages of constituent company returns. The EEI Index return shown above is cap-weighted.
** Diversified category eliminated in 2017 due to lack of constituent companies.
Source: EEI Finance Department, S&P Global Market Intelligence

IX. Sector Comparison, Trailing 3 mo. Total Return

For the three-month period ending 09/30/2019

Sector	Total Return
Telecommunications	10.3%
Utilities	8.8%
EEI Index	8.2%
Consumer Goods	4.7%
Technology	3.3%
Financials	3.0%
Industrials	0.7%
Consumer Services	-0.7%
Basic Materials	-2.3%
Healthcare	-2.7%
Oil & Gas	-6.9%

Note: Sector Comparison page based on the Dow Jones U.S. Indexes, which are market-capitalization-weighted indices.
Source: EEI Finance Dept., Dow Jones & Company, Google Finance, Y Charts

X. Sector Comparison, Trailing 12 mo. Total Return

For the twelve-month period ending 09/30/2019

Sector	Total Return
EEI Index	26.6%
Utilities	25.5%
Telecommunications	18.3%
Consumer Goods	9.4%
Financials	8.4%
Technology	6.4%
Industrials	3.5%
Consumer Services	3.1%
Basic Materials	-4.1%
Healthcare	-4.6%
Oil & Gas	-21.7%

Note: Sector Comparison page based on the Dow Jones U.S. Indexes, which are market-capitalization-weighted indices.
Source: EEI Finance Dept., Dow Jones & Company, Google Finance, Y Charts

XI. Market Capitalization at September 30, 2019 (in $ Billions)

U.S. Investor-Owned Electric Utilities

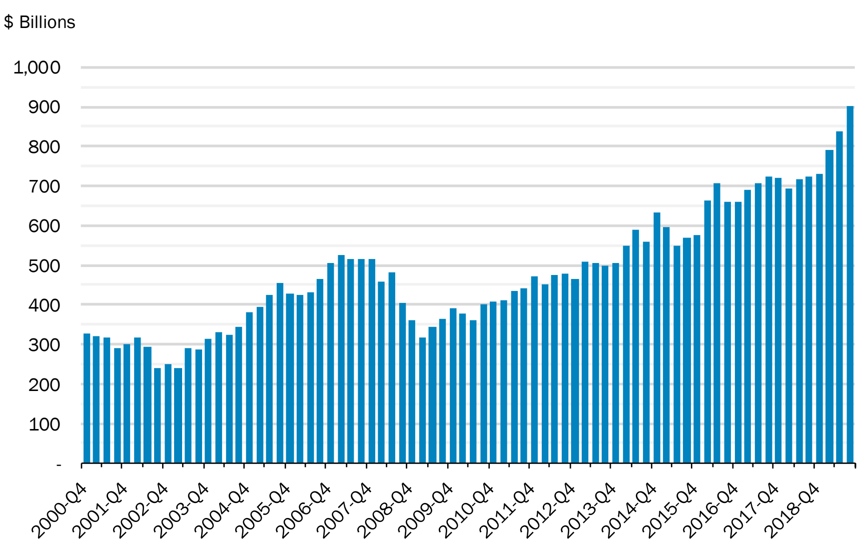
Company	Stock Symbol	$ Market Cap	% Total
NextEra Energy, Inc.	NEE	111.6	12.36%
Duke Energy Corporation	DUK	69.8	7.73%
Dominion Energy, Inc.	D	65.0	7.21%
Southern Company	SO	64.5	7.15%
Exelon Corporation	EXC	47.0	5.20%
American Electric Power Co., Inc.	AEP	46.2	5.12%
Sempra Energy	SRE	40.6	4.50%
Xcel Energy Inc.	XEL	33.5	3.71%
Public Service Enter. Group Inc.	PEG	31.3	3.47%
Consolidated Edison, Inc.	ED	31.0	3.44%
WEC Energy Group, Inc.	WEC	30.0	3.32%
Eversource Energy	ES	27.3	3.03%
FirstEnergy Corp.	FE	25.7	2.84%
Edison International	EIX	24.6	2.72%
DTE Energy Company	DTE	24.3	2.70%
PPL Corporation	PPL	22.7	2.52%
Entergy Corporation	ETR	22.7	2.51%
Ameren Corporation	AEE	19.7	2.18%
CMS Energy Corporation	CMS	18.1	2.00%
Evergy, Inc.	EVRG	16.2	1.79%
AVANGRID, Inc.	AGR	16.2	1.79%

Company	Stock Symbol	$ Market Cap	% Total
CenterPoint Energy, Inc.	CNP	15.2	1.68%
Alliant Energy Corporation	LNT	12.8	1.42%
NiSource Inc.	NI	11.2	1.24%
Pinnacle West Capital Corp.	PNW	10.9	1.21%
OGE Energy Corp.	OGE	9.1	1.01%
IDACORP, Inc.	IDA	5.7	0.63%
MDU Resources Group, Inc.	MDU	5.6	0.62%
PG&E Corporation	PCG	5.3	0.59%
Portland General Electric Co.	POR	5.0	0.56%
Hawaiian Electric Industries, Inc.	HE	5.0	0.55%
Black Hills Corporation	BKH	4.6	0.51%
ALLETE, Inc.	ALE	4.5	0.50%
PNM Resources, Inc.	PNM	4.2	0.46%
NorthWestern Corporation	NWE	3.8	0.42%
Avista Corporation	AVA	3.2	0.35%
MGE Energy, Inc.	MGEE	2.8	0.31%
El Paso Electric Company	EE	2.7	0.30%
Otter Tail Corporation	OTTR	2.1	0.24%
Unitil Corporation	UTL	0.9	0.10%
Total Industry		**902.4**	**100.00%**

Source: EEI Finance Dept., S&P Global Market Intelligence

XII. EEI Index Market Capitalization (at Period End)

U.S. Investor-Owned Electric Utilities



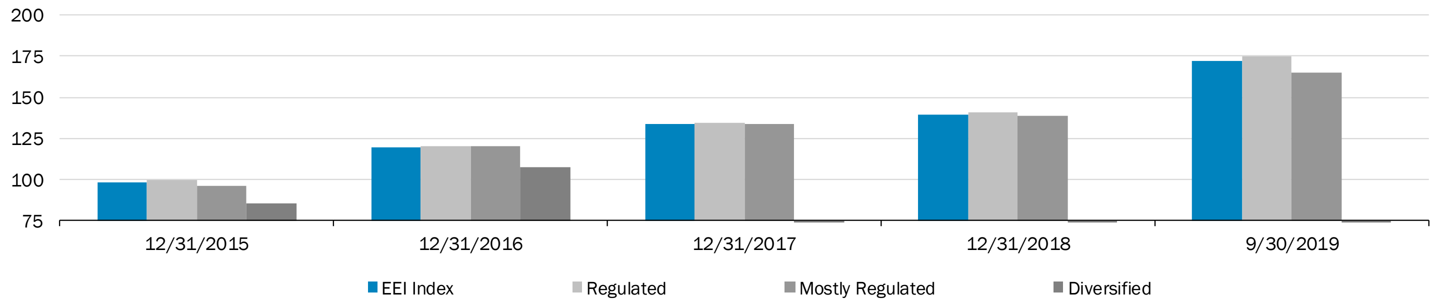
Note: Change in EEI Index market capitalization reflects the impact of buyout and spin-off activity in addition to stock market performance.
Source: EEI Finance Dept., S&P Global Market Intelligence

EEI Index Market Cap (in $ Billions)

2003-Q4	314	2011-Q4	472
2004-Q1	330	2012-Q1	451
2004-Q2	323	2012-Q2	475
2004-Q3	342	2012-Q3	480
2004-Q4	380	2012-Q4	464
2005-Q1	396	2013-Q1	507
2005-Q2	426	2013-Q2	505
2005-Q3	455	2013-Q3	500
2005-Q4	429	2013-Q4	504
2006-Q1	423	2014-Q1	548
2006-Q2	433	2014-Q2	588
2006-Q3	464	2014-Q3	557
2006-Q4	504	2014-Q4	632
2007-Q1	525	2015-Q1	597
2007-Q2	516	2015-Q2	549
2007-Q3	515	2015-Q3	568
2007-Q4	514	2015-Q4	577
2008-Q1	457	2016-Q1	663
2008-Q2	482	2016-Q2	706
2008-Q3	404	2016-Q3	659
2008-Q4	362	2016-Q4	660
2009-Q1	316	2017-Q1	690
2009-Q2	344	2017-Q2	708
2009-Q3	363	2017-Q3	722
2009-Q4	390	2017-Q4	720
2010-Q1	377	2018-Q1	692
2010-Q2	360	2018-Q2	716
2010-Q3	402	2018-Q3	725
2010-Q4	407	2018-Q4	731
2011-Q1	411	2019-Q1	790
2011-Q2	433	2019-Q2	838
2011-Q3	442	2019-Q3	902

XIII. Comparative Category Total Annual Returns

U.S. Investor-Owned Electric Utilities, Value of $100 invested at close on 12/31/2014



	2014	2015	2016	2017	2018	9/30/2019
EEI Index Annual Return (%)		(2.05)	22.21	11.56	4.28	23.52
EEI Index Cumulative Return ($)	100.00	97.95	119.70	133.54	139.25	172.00
Regulated EEI Index Annual Return		(0.67)	21.16	11.66	4.55	24.74
Regulated EEI Index Cumulative Return	100.00	99.33	120.34	134.37	140.48	175.24
Mostly Regulated EEI Index Annual Return		(3.67)	24.57	11.32	3.62	19.30
Mostly Regulated EEI Index Cumulative Return	100.00	96.33	119.99	133.58	138.41	165.12
Diversified EEI Index Annual Return		(14.43)	25.59	-	-	-
Diversified EEI Index Cumulative Return	100.00	85.57	107.47	-	-	-

Calendar year returns shown, except where noted.
Diversified category eliminated in 2017 due to lack of constituent companies.
Returns are unweighted averages of constituent company returns.
Source: EEI Finance Dept., S&P Global Market Intelligence

for the first nine months of the year, well above the 17% to 20% gains posted by the major averages. The EEI Index's relative performance is even more pronounced over the trailing year, as the market's 20% correction last fall/winter created a favorable starting point for the 2019 results. The EEI Index returned 26.6% for the year ending September 30 compared with about 4.3% for the broad market, and surpassed all S&P 500 sectors for the period, edging out the S&P Utilities sector's 25.5% return.

Rates Fall on Slowing Economic Growth

Utility shares' aggregate short-term relative performance is typically driven by evolving macroeconomic trends rather than surprises in the industry's slow-changing fundamental outlook. U.S. real gross domestic product (GDP) growth slowed to a 2.0% rate in Q2 and 1.9% in Q3 from 3.1% in Q1. S&P 500 company profits were about flat year-to-year in Q2 and Q3 with revenue up about 4% each quarter, according to Zack's Investment Research data. S&P 500 profits grew more than 20% in calendar year 2018 on nearly 10% revenue growth as the Trump Administration's economic stimulus and reduced tax rates took effect. S&P 500 profits are expected to be about flat for 2019.

The utility sector's predictable mid-single digit earnings growth, with similar dividend growth, seems favorable by comparison. Wall Street's outlook remains upbeat for 2020, with corporate profits and revenue set to grow 8% to 9% and just under 5%, respectively. But that forecast is premised on the very long-lived economic expansion finding new life.

The U.S. Federal Reserve cut short-term rates twice during Q3 (on July 31 and September 18), citing continued low inflation and the spillover effect from slowing growth overseas. The Fed Funds target fell from a range of 2.25% to

XIV. EEI Index Top Ten Performers

For the six-month period ending 9/30/2019

Company	% Return	Category
Southern Company	45.3	R
WEC Energy Group, Inc.	40.2	R
Entergy Corporation	39.9	R
Sempra Energy	39.4	R
Edison International	36.5	R
NextEra Energy, Inc.	36.5	MR
El Paso Electric Company	36.2	R
MGE Energy, Inc.	35.1	R
Xcel Energy Inc.	34.4	R
Eversource Energy	34.2	R

Note: Return figures include capital gains and dividends.
R = Regulated, MR = Mostly Regulated
Source: EEI Finance Department

2.50% in early July to 1.75% to 2.00% by late September. The 10-year Treasury bond yield reached a low of 1.5% in early September, down from a recent peak of 3.2% just a year earlier, before edging higher as the quarter ended.

U.S. Electric Output Declines

The multi-year stagnation in electric power demand persisted during the first nine months of 2019. U.S. electric output in the contiguous 48 states declined 0.6% in Q3 after falling 4.4% year-to-year in Q2. Part of the shortfall in both quarters was weather-related; cooling degree days fell 11% year-to-year nationwide in Q2 and 2% in Q3, although Q3 was hotter than normal and cooling degree days were more than 20% above the historical average.

Analysts have also cited the impact of trade tariffs on U.S. industrial demand as well as the ongoing impact of years of energy efficiency initiatives nationwide. Softness in load continued to be a point noted in analyst reports during the quarter.

Industry Growth Outlook Remains Healthy

There was little change in the industry's stable business fundamentals in Q3. In fact, analyst reports roundly noted that the visible horizon for long-term capex and rate base growth seemed to extend even farther into the future. Utility investment programs include new renewables generation, new gas-fired generation, transmission and distribution modernization and expansion, smart-grid deployment, and reliability-related network hardening among other projects. Some analysts questioned whether the growing variety and diversity of programs may be a sign of excess. Nevertheless, they seem to view state regulatory relations as generally fair, balancing the interests of ratepayers, utilities and other stakeholders. Most stakeholders across the political spectrum support investments that advance renewable energy goals, reliability, job creation and the enlarged tax base that comes with it. Some utilities have successfully advocated for changes to rate design — such as forward test years, rate mechanisms and adjustment clauses — that allow timely recovery of costs associated with big-ticket capital investment programs and offer some protection from lethargic demand. The vision of an industry poised to deliver mid-single-digit earnings growth, a near 3% dividend yield and dividend growth remained very much in tact as Q3 closed.

Favorable Cost Trends

Other favorable fundamental trends for regulated utilities include continued low fuel costs. Coal prices have declined steadily since 2011 and natural gas prices have changed little in recent years. The low level of interest rates is also beneficial. Since regulated utilities pass fuel and interest expense through to customers (and fuel can account for 40% or more of the customer's bill), cost stability in these key areas helps keep bill inflation down and makes it easier to gain regulatory approval for rate base expansion. Despite steep capex growth in recent years, the average nationwide cost of electricity for residential customers has only risen from $0.1151/kilowatt hour (kWh) in 2009 to $0.1289/kWh in 2018, which was unchanged from 2017 and only marginally higher than 2014's $0.1252, according to EIA data. One industry analyst noted in Q3 that electric affordability is the best it has been since 1972, measured as a percent of disposable income, with electricity costs accounting for less than 1% of consumer spending and ranking 13th on the list of household expense burdens.

Can Elevated Valuations Rise Farther?

Wall Street analysts generally view utility stock valuations as high when measured by price/earnings (PE) ratios relative to the S&P 500 and to history. One reason for this is the very low level of interest rates both in the U.S. and overseas. The U.S. 10-year Treasury yield was about 6% in the late 1990s, more than triple today's level, while bond markets in Europe and Japan sport widespread negative yields. Another reason is the strong fundamentals that underpin prospects for total returns in excess of 8% (5% from earnings growth and 3% from the dividend). Given this outlook, the view seems to be that utilities offer enough value to lift multiples higher still, particularly if global economic growth turns down and interest rates fall to new lows.

Other Risks

A sharp rise in interest rates is widely seen as the biggest macro threat facing utility investors. Although that has been said for years and interest rates just seem to fall. Inflation held near 2% throughout 2018 even as the economy roared and hasn't moved this year either. The main risk to the very long-lived economic expansion seems to be weakness rather than red-hot growth.

Analysts note that the impact of rising rates would be on stock prices rather than earnings. Higher rates can translate into higher allowed ROEs and improved pension funding. Many companies have embedded low-cost debt from years of low rates, and interest rates could rise while remaining very low by historical standards.

A second, less discussed risk is pushback on rate increases needed to fund capex programs. Stable fuel costs and low interest rates have kept rate pressures muted and industry analysts expect that trend will continue. But if the economy enters recession and consumer incomes fall, managing regulatory risk and financing needed capex through customer rates may become more challenging than it has been in recent years.■

Press Release

October 29, 2014

Federal Reserve issues FOMC statement

For immediate release

Share

Information received since the Federal Open Market Committee met in September suggests that economic activity is expanding at a moderate pace. Labor market conditions improved somewhat further, with solid job gains and a lower unemployment rate. On balance, a range of labor market indicators suggests that underutilization of labor resources is gradually diminishing. Household spending is rising moderately and business fixed investment is advancing, while the recovery in the housing sector remains slow. Inflation has continued to run below the Committee's longer-run objective. Market-based measures of inflation compensation have declined somewhat; survey-based measures of longer-term inflation expectations have remained stable.

Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The Committee expects that, with appropriate policy accommodation, economic activity will expand at a moderate pace, with labor market indicators and inflation moving toward levels the Committee judges consistent with its dual mandate. The Committee sees the risks to the outlook for economic activity and the labor market as nearly balanced. Although inflation in the near term will likely be held down by lower energy prices and other factors, the Committee judges that the likelihood of inflation running persistently below 2 percent has diminished somewhat since early this year.

The Committee judges that there has been a substantial improvement in the outlook for the labor market since the inception of its current asset purchase program. Moreover, the Committee continues to see sufficient underlying strength in the broader economy to support ongoing progress toward maximum employment in a context of price stability. Accordingly, the Committee decided to conclude its asset purchase program this month. The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction. This policy, by keeping the Committee's holdings of longer-term securities at sizable levels, should help maintain accommodative financial conditions.

To support continued progress toward maximum employment and price stability, the Committee today reaffirmed its view that the current 0 to 1/4 percent target range for the federal funds rate remains appropriate. In determining how long to maintain this target range, the Committee will assess progress--both realized and expected--toward its objectives of maximum employment and 2 percent inflation. This assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial developments. The Committee anticipates, based on its current assessment, that it likely will be appropriate to maintain the 0 to 1/4 percent target range for the federal funds rate for a considerable time following the end of its asset purchase program this month, especially if projected inflation continues to run below the Committee's 2 percent longer-run goal, and provided that longer-term inflation expectations remain well anchored. However, if incoming information indicates faster progress toward the Committee's employment and inflation objectives than the Committee now expects, then increases in the target range for the federal funds rate are likely to occur sooner than currently anticipated. Conversely, if progress proves slower than expected, then increases in the target range are likely to occur later than currently anticipated.

When the Committee decides to begin to remove policy accommodation, it will take a balanced approach consistent with its longer-run goals of maximum employment and inflation of 2 percent. The Committee currently anticipates that, even after employment and inflation are near mandate-consistent levels, economic conditions may, for some time, warrant keeping the target federal funds rate below levels the Committee views as normal in the longer run.

Voting for the FOMC monetary policy action were: Janet L. Yellen, Chair; William C. Dudley, Vice Chairman; Lael Brainard; Stanley Fischer; Richard W. Fisher; Loretta J. Mester; Charles I. Plosser; Jerome H. Powell; and Daniel K. Tarullo. Voting against the action was Narayana Kocherlakota, who believed that, in light of continued sluggishness in the inflation outlook and the recent slide in market-based measures of longer-term inflation expectations, the Committee should commit to keeping the current target range for the federal funds rate at least until the one-to-two-year ahead inflation outlook has returned to 2 percent and should continue the asset purchase program at its current level.

Statement Regarding Purchases of Treasury Securities and Agency Mortgage-Backed Securities

Statement Regarding Purchases of Treasury Securities and Agency Mortgage-Backed Securities

Last Update: October 29, 2014

Press Release

November 03, 2010

FOMC statement

For immediate release

Share

Information received since the Federal Open Market Committee met in September confirms that the pace of recovery in output and employment continues to be slow. Household spending is increasing gradually, but remains constrained by high unemployment, modest income growth, lower housing wealth, and tight credit. Business spending on equipment and software is rising, though less rapidly than earlier in the year, while investment in nonresidential structures continues to be weak. Employers remain reluctant to add to payrolls. Housing starts continue to be depressed. Longer-term inflation expectations have remained stable, but measures of underlying inflation have trended lower in recent quarters.

Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. Currently, the unemployment rate is elevated, and measures of underlying inflation are somewhat low, relative to levels that the Committee judges to be consistent, over the longer run, with its dual mandate. Although the Committee anticipates a gradual return to higher levels of resource utilization in a context of price stability, progress toward its objectives has been disappointingly slow.

To promote a stronger pace of economic recovery and to help ensure that inflation, over time, is at levels consistent with its mandate, the Committee decided today to expand its holdings of securities. The Committee will maintain its existing policy of reinvesting principal payments from its securities holdings. In addition, the Committee intends to purchase a further $600 billion of longer-term Treasury securities by the end of the second quarter of 2011, a pace of about $75 billion per month. The Committee will regularly review the pace of its securities purchases and the overall size of the asset-purchase program in light of incoming information and will adjust the program as needed to best foster maximum employment and price stability.

The Committee will maintain the target range for the federal funds rate at 0 to 1/4 percent and continues to anticipate that economic conditions, including low rates of resource utilization, subdued inflation trends, and stable inflation expectations, are likely to warrant exceptionally low levels for the federal funds rate for an extended period.

The Committee will continue to monitor the economic outlook and financial developments and will employ its policy tools as necessary to support the economic recovery and to help ensure that inflation, over time, is at levels consistent with its mandate.

Voting for the FOMC monetary policy action were: Ben S. Bernanke, Chairman; William C. Dudley, Vice Chairman; James Bullard; Elizabeth A. Duke; Sandra Pianalto; Sarah Bloom Raskin; Eric S. Rosengren; Daniel K. Tarullo; Kevin M. Warsh; and Janet L. Yellen.

Voting against the policy was Thomas M. Hoenig. Mr. Hoenig believed the risks of additional securities purchases outweighed the benefits. Mr. Hoenig also was concerned that this continued high level of monetary accommodation increased the risks of future financial imbalances and, over time, would cause an increase in long-term inflation expectations that could destabilize the economy.

Statement from Federal Reserve Bank of New York

Table 1. Economic projections of Federal Reserve Board members and Federal Reserve Bank presidents, under their individual assumptions of projected appropriate monetary policy, September 2019

Advance release of table 1 of the Summary of Economic Projections to be released with the FOMC minutes

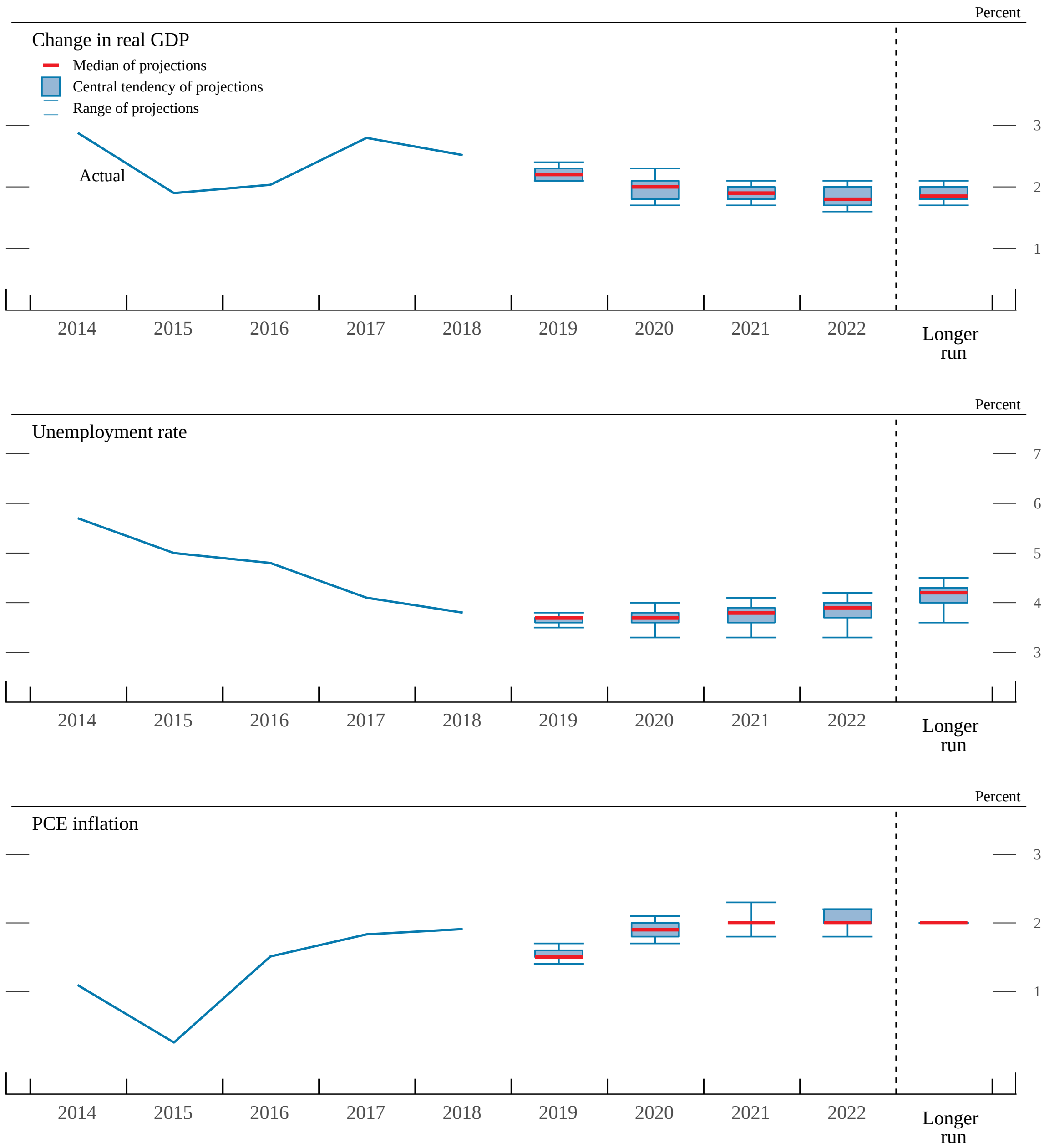
Percent

Variable	Median[1]					Central Tendency[2]					Range[3]				
	2019	2020	2021	2022	Longer run	2019	2020	2021	2022	Longer run	2019	2020	2021	2022	Longer run
Change in real GDP	2.2	2.0	1.9	1.8	1.9	2.1–2.3	1.8–2.1	1.8–2.0	1.7–2.0	1.8–2.0	2.1–2.4	1.7–2.3	1.7–2.1	1.6–2.1	1.7–2.1
June projection	2.1	2.0	1.8		1.9	2.0–2.2	1.8–2.2	1.8–2.0		1.8–2.0	2.0–2.4	1.5–2.3	1.5–2.1		1.7–2.1
Unemployment rate	3.7	3.7	3.8	3.9	4.2	3.6–3.7	3.6–3.8	3.6–3.9	3.7–4.0	4.0–4.3	3.5–3.8	3.3–4.0	3.3–4.1	3.3–4.2	3.6–4.5
June projection	3.6	3.7	3.8		4.2	3.6–3.7	3.5–3.9	3.6–4.0		4.0–4.4	3.5–3.8	3.3–4.0	3.3–4.2		3.6–4.5
PCE inflation	1.5	1.9	2.0	2.0	2.0	1.5–1.6	1.8–2.0	2.0	2.0–2.2	2.0	1.4–1.7	1.7–2.1	1.8–2.3	1.8–2.2	2.0
June projection	1.5	1.9	2.0		2.0	1.5–1.6	1.9–2.0	2.0–2.1		2.0	1.4–1.7	1.8–2.1	1.9–2.2		2.0
Core PCE inflation[4]	1.8	1.9	2.0	2.0		1.7–1.8	1.9–2.0	2.0	2.0–2.2		1.6–1.8	1.7–2.1	1.8–2.3	1.8–2.2	
June projection	1.8	1.9	2.0			1.7–1.8	1.9–2.0	2.0–2.1			1.4–1.8	1.8–2.1	1.8–2.2		
Memo: Projected appropriate policy path															
Federal funds rate	1.9	1.9	2.1	2.4	2.5	1.6–2.1	1.6–2.1	1.6–2.4	1.9–2.6	2.5–2.8	1.6–2.1	1.6–2.4	1.6–2.6	1.6–2.9	2.0–3.3
June projection	2.4	2.1	2.4		2.5	1.9–2.4	1.9–2.4	1.9–2.6		2.5–3.0	1.9–2.6	1.9–3.1	1.9–3.1		2.4–3.3

Note: Projections of change in real gross domestic product (GDP) and projections for both measures of inflation are percent changes from the fourth quarter of the previous year to the fourth quarter of the year indicated. PCE inflation and core PCE inflation are the percentage rates of change in, respectively, the price index for personal consumption expenditures (PCE) and the price index for PCE excluding food and energy. Projections for the unemployment rate are for the average civilian unemployment rate in the fourth quarter of the year indicated. Each participant's projections are based on his or her assessment of appropriate monetary policy. Longer-run projections represent each participant's assessment of the rate to which each variable would be expected to converge under appropriate monetary policy and in the absence of further shocks to the economy. The projections for the federal funds rate are the value of the midpoint of the projected appropriate target range for the federal funds rate or the projected appropriate target level for the federal funds rate at the end of the specified calendar year or over the longer run. The June projections were made in conjunction with the meeting of the Federal Open Market Committee on June 18-19, 2019. One participant did not submit longer-run projections for the change in real GDP, the unemployment rate, or the federal funds rate in conjunction with the June 18-19, 2019, meeting, and one participant did not submit such projections in conjunction with the September 17-18, 2019, meeting.

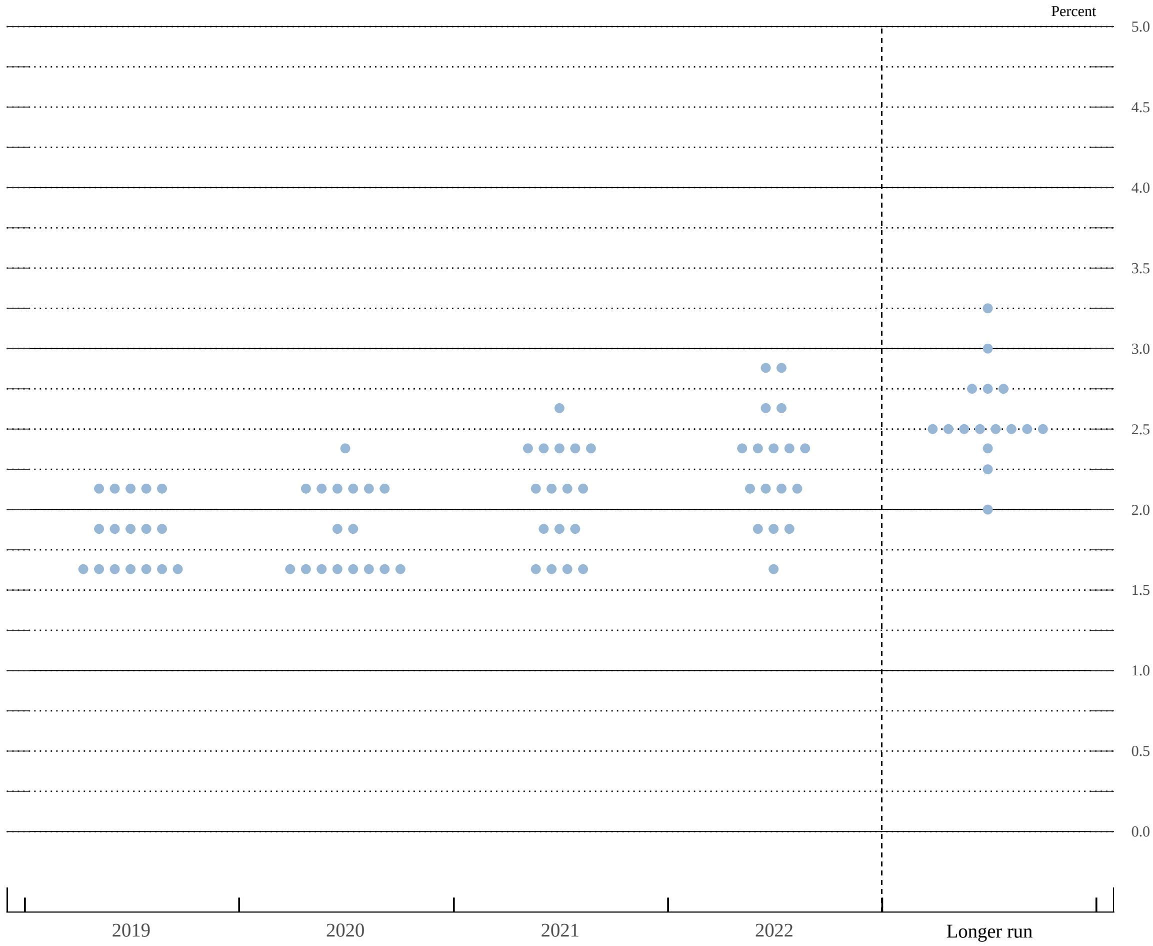
1. For each period, the median is the middle projection when the projections are arranged from lowest to highest. When the number of projections is even, the median is the average of the two middle projections.
2. The central tendency excludes the three highest and three lowest projections for each variable in each year.
3. The range for a variable in a given year includes all participants' projections, from lowest to highest, for that variable in that year.
4. Longer-run projections for core PCE inflation are not collected.

Figure 1. Medians, central tendencies, and ranges of economic projections, 2019-22 and over the longer run



Note. Definitions of variables and other explanations are in the notes to table 1. The data for the actual values of the variables are annual.

Figure 2. FOMC participants' assessments of appropriate monetary policy: Midpoint of target range or target level for the federal funds rate



Note. Each shaded circle indicates the value (rounded to the nearest 1/8 percentage point) of an individual participant's judgment of the midpoint of the appropriate target range for the federal funds rate or the appropriate target level for the federal funds rate at the end of the specified calendar year or over the longer run. One participant did not submit longer-run projections for the federal funds rate.

For release at 2:00 p.m., EDT, September 18, 2019

Explanation of Economic Projections Charts

The charts show actual values and projections for three economic variables, based on FOMC participants' individual assessments of appropriate monetary policy:

- Change in Real Gross Domestic Product (GDP)—as measured from the fourth quarter of the previous year to the fourth quarter of the year indicated.
- Unemployment Rate—the average civilian unemployment rate in the fourth quarter of each year.
- PCE Inflation—as measured by the change in the personal consumption expenditures (PCE) price index from the fourth quarter of the previous year to the fourth quarter of the year indicated.

Information for these variables is shown for each year from 2014 to 2022, and for the longer run.

The solid blue line, labeled "Actual," shows the historical values for each variable.

The solid red lines depict the median projection in each period for each variable. The median value in each period is the middle projection when the projections are arranged from lowest to highest. When the number of projections is even, the median is the average of the two middle projections.

The range and central tendency for each variable in each projection period are depicted in "box and whiskers" format. The blue connected horizontal and vertical lines ("whiskers") represent the range of the projections of policymakers. The bottom of the range for each variable is the lowest of all of the projections for that year or period. Likewise, the top of the range is the highest of all of the projections for that year or period. The light blue shaded boxes represent the central tendency, which is a narrower version of the range that excludes the three highest and three lowest projections for each variable in each year or period.

The longer-run projections, which are shown on the far right side of the charts, are the rates of growth, unemployment, and inflation to which a policymaker expects the economy to converge over time—maybe in five or six years—in the absence of further shocks and under appropriate monetary policy. Because appropriate monetary policy, by definition, is aimed at achieving the Federal Reserve's dual mandate of maximum employment and price stability in the longer run, policymakers' longer-run projections for economic growth and unemployment may be interpreted, respectively, as estimates of the economy's normal or trend rate of growth and its normal unemployment rate over the longer run. The longer-run projection shown for inflation is the rate of inflation judged to be most consistent with the Federal Reserve's dual mandate.

For release at 2:00 p.m., EDT, September 18, 2019

Explanation of Policy Path Chart

This chart is based on policymakers' assessments of appropriate monetary policy, which, by definition, is the future path of policy that each participant deems most likely to foster outcomes for economic activity and inflation that best satisfy his or her interpretation of the Federal Reserve's dual objectives of maximum employment and stable prices.

Each shaded circle indicates the value (rounded to the nearest ⅛ percentage point) of an individual participant's judgment of the midpoint of the appropriate target range for the federal funds rate or the appropriate target level for the federal funds rate at the end of the specified calendar year or over the longer run.

FEDERAL RESERVE press release

For release at 2 p.m. EDT October 30, 2019

Information received since the Federal Open Market Committee met in September indicates that the labor market remains strong and that economic activity has been rising at a moderate rate. Job gains have been solid, on average, in recent months, and the unemployment rate has remained low. Although household spending has been rising at a strong pace, business fixed investment and exports remain weak. On a 12-month basis, overall inflation and inflation for items other than food and energy are running below 2 percent. Market-based measures of inflation compensation remain low; survey-based measures of longer-term inflation expectations are little changed.

Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. In light of the implications of global developments for the economic outlook as well as muted inflation pressures, the Committee decided to lower the target range for the federal funds rate to 1-1/2 to 1-3/4 percent. This action supports the Committee's view that sustained expansion of economic activity, strong labor market conditions, and inflation near the Committee's symmetric 2 percent objective are the most likely outcomes, but uncertainties about this outlook remain. The Committee will continue to monitor the implications of incoming information for the economic outlook as it assesses the appropriate path of the target range for the federal funds rate.

In determining the timing and size of future adjustments to the target range for the federal funds rate, the Committee will assess realized and expected economic conditions relative to its maximum employment objective and its symmetric 2 percent inflation objective. This assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial and international developments.

(more)

Voting for the monetary policy action were Jerome H. Powell, Chair; John C. Williams, Vice Chair; Michelle W. Bowman; Lael Brainard; James Bullard; Richard H. Clarida; Charles L. Evans; and Randal K. Quarles. Voting against this action were: Esther L. George and Eric S. Rosengren, who preferred at this meeting to maintain the target range at 1-3/4 percent to 2 percent.

- 0 -

For release at 2 p.m. EDT October 30, 2019

Decisions Regarding Monetary Policy Implementation

The Federal Reserve has made the following decisions to implement the monetary policy stance announced by the Federal Open Market Committee in its statement on October 30, 2019:

- The Board of Governors of the Federal Reserve System voted unanimously to lower the interest rate paid on required and excess reserve balances to 1.55 percent, effective October 31, 2019.
- As part of its policy decision, the Federal Open Market Committee voted to authorize and direct the Open Market Desk at the Federal Reserve Bank of New York, until instructed otherwise, to execute transactions in the System Open Market Account in accordance with the following domestic policy directive:

  "Effective October 31, 2019, the Federal Open Market Committee directs the Desk to undertake open market operations as necessary to maintain the federal funds rate in a target range of 1-1/2 to 1-3/4 percent. In light of recent and expected increases in the Federal Reserve's non-reserve liabilities, the Committee directs the Desk to purchase Treasury bills at least into the second quarter of next year to maintain over time ample reserve balances at or above the level that prevailed in early September 2019. The Committee also directs the Desk to conduct term and overnight repurchase agreement operations at least through January of next year to ensure that the supply of reserves remains ample even during periods of sharp increases in non-reserve liabilities, and to mitigate the risk of money market pressures that could adversely affect policy implementation. In addition, the Committee directs the Desk to conduct overnight reverse repurchase operations (and reverse repurchase operations with maturities of more than one day when necessary to accommodate weekend, holiday, or similar trading conventions) at an offering rate of 1.45 percent, in amounts limited only by the value of Treasury securities held outright in the System Open Market Account that are available for such operations and by a per-counterparty limit of $30 billion per day.

  The Committee directs the Desk to continue rolling over at auction all principal payments from the Federal Reserve's holdings of Treasury securities and to continue reinvesting all principal payments from the Federal Reserve's holdings of agency debt and agency mortgage-backed securities received during each calendar month. Principal payments from agency debt and agency mortgage-backed securities up to $20 billion per month will continue to be reinvested in Treasury securities to roughly match the maturity composition of Treasury securities outstanding; principal payments in excess of $20 billion per month will continue to be reinvested in agency mortgage-backed securities. Small deviations from these amounts for operational reasons are acceptable.

(more)

> The Committee also directs the Desk to engage in dollar roll and coupon swap transactions as necessary to facilitate settlement of the Federal Reserve's agency mortgage-backed securities transactions."

- In a related action, the Board of Governors of the Federal Reserve System voted unanimously to approve a 1/4 percentage point decrease in the primary credit rate to 2.25 percent, effective October 31, 2019. In taking this action, the Board approved requests to establish that rate submitted by the Boards of Directors of the Federal Reserve Banks of Minneapolis and San Francisco.

This information will be updated as appropriate to reflect decisions of the Federal Open Market Committee or the Board of Governors regarding details of the Federal Reserve's operational tools and approach used to implement monetary policy.

More information regarding open market operations and reinvestments may be found on the Federal Reserve Bank of New York's website.

Fortis Inc. (FTS.TO)

Toronto - Toronto Delayed Price. Currency in CAD

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Quote Lookup

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Time Period: Dec 08, 2018 - Dec 08, 2019

Show: Historical Prices

Frequency: Monthly

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Currency in CAD

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Date	Open	High	Low	Close*	Adj Close**	Volume
Dec 06, 2019	52.49	53.04	52.34	52.79	52.79	1,257,652
Dec 01, 2019	52.08	52.57	51.73	52.40	52.40	7,431,800
Nov 18, 2019				**0.4775** Dividend		
Oct 31, 2019	54.75	55.36	51.65	52.04	51.58	35,569,900
Sep 30, 2019	56.00	56.94	53.24	54.72	54.23	24,627,500
Aug 31, 2019	55.01	56.79	54.70	56.01	55.51	24,185,500
Aug 19, 2019				**0.45** Dividend		
Jul 31, 2019	51.92	55.31	51.62	54.97	54.03	21,516,100
Jun 30, 2019	51.59	52.90	51.44	52.02	51.13	15,386,200
May 31, 2019	51.12	52.95	50.95	51.71	50.83	22,571,400
May 16, 2019				**0.45** Dividend		
Apr 30, 2019	49.46	51.35	49.13	51.05	49.73	27,292,000
Mar 31, 2019	49.27	50.47	48.88	49.52	48.24	21,753,300
Mar 01, 2019	47.66	50.06	47.22	49.39	48.11	26,985,300
Feb 14, 2019				**0.45** Dividend		
Feb 01, 2019	46.93	48.10	46.11	47.45	45.78	22,820,500
Jan 01, 2019	45.43	46.96	44.00	46.86	45.21	24,601,700

*Close price adjusted for splits. **Adjusted close price adjusted for both dividends and splits.

People Also Watch

Symbol	Last Price	Change	% Change
EMA.TO EMERA INCORPORATED	55.34	+0.30	+0.55%
ENB.TO ENBRIDGE INC	51.10	+0.37	+0.73%
TRP.TO TC ENERGY CORP.	67.35	+0.51	+0.76%
T.TO TELUS CORPORATION	51.25	+0.39	+0.77%
BCE.TO BCE INC.	64.57	+0.54	+0.84%

Ameren Corporation (AEE)

NYSE - Nasdaq Real Time Price. Currency in USD

75.05 -0.14 (-0.19%)

Buy Sell

As of 12:32PM EST. Market open.

Currency in USD

Earnings Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	8	4	12	12
Avg. Estimate	0.31	0.77	3.26	3.48
Low Estimate	0.25	0.73	3.19	3.4
High Estimate	0.37	0.82	3.35	3.57
Year Ago EPS	0.28	0.78	3.37	3.26

Revenue Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	4	3	9	9
Avg. Estimate	1.65B	1.61B	6.27B	6.5B
Low Estimate	1.43B	1.57B	6.04B	6.12B
High Estimate	1.86B	1.67B	6.59B	6.78B
Year Ago Sales	1.42B	1.62B	6.29B	6.27B
Sales Growth (year/est)	16.00%	-0.70%	-0.30%	3.70%

Earnings History	12/30/2018	3/30/2019	6/29/2019	9/29/2019
EPS Est.	0.32	0.68	0.75	1.45
EPS Actual	0.28	0.78	0.72	1.47
Difference	-0.04	0.1	-0.03	0.02
Surprise %	-12.50%	14.70%	-4.00%	1.40%

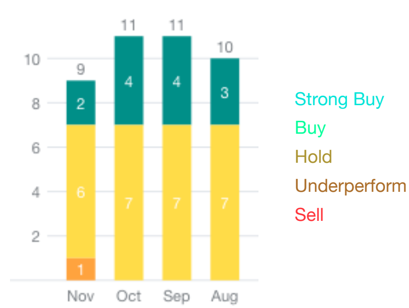
EPS Trend	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Current Estimate	0.31	0.77	3.26	3.48
7 Days Ago	0.31	0.77	3.26	3.48
30 Days Ago	0.3	0.78	3.26	3.5
60 Days Ago	0.28	0.79	3.24	3.5
90 Days Ago	0.29	0.79	3.24	3.51

EPS Revisions	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Up Last 7 Days	3	N/A	2	N/A

People Also Watch

Symbol	Last Price	Change	% Change
DTE DTE Energy Company	123.27	-0.10	-0.08%
AJG Arthur J. Gallagher & Co.	91.45	-0.65	-0.70%
CMS CMS Energy Corporation	61.71	-0.24	-0.40%
ABC AmerisourceBergen Corporation	89.95	+1.64	+1.86%
AEP American Electric Power Company	91.14	+0.07	+0.08%

Recommendation Trends >



Recommendation Rating >

Up Last 30 Days	4	N/A	2	N/A
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	1	N/A	4

Growth Estimates	AEE	Industry	Sector	S&P 500
Current Qtr.	10.70%	N/A	N/A	0.02
Next Qtr.	-1.30%	N/A	N/A	0.06
Current Year	-3.30%	N/A	N/A	-0.03
Next Year	6.70%	N/A	N/A	0.14
Next 5 Years (per annum)	4.70%	N/A	N/A	0.07
Past 5 Years (per annum)	8.24%	N/A	N/A	N/A

1 Strong Buy	2 Buy	3 Hold	4 Under-perform	5 Sell

Analyst Price Targets (9) ›

Average 81.22

Low 76.00 High 86.00

Current 75.05

Upgrades & Downgrades ›

Maintains	Wells Fargo: to Outperform	11/11/2019
Upgrade	UBS: Neutral to Buy	10/29/2019
Maintains	SunTrust Robinson Humphrey: to Hold	10/16/2019
Maintains	Morgan Stanley: to Equal-Weight	9/25/2019
Upgrade	Bank of America: Neutral to Buy	9/17/2019
Upgrade	Wolfe Research: Peer Perform to Outperform	9/12/2019

More Upgrades & Downgrades

Yahoo Small Business

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Avista Corporation (AVA)

NYSE - Nasdaq Real Time Price. Currency in USD

Add to watchlist | Visitors trend 2W ↓ 10W ↑ 9M ↑

Quote Lookup

46.43 -0.22 (-0.47%)

As of 12:33PM EST. Market open.

Buy Sell

Summary | Company Outlook | Chart | Conversations | Statistics | Historical Data | Profile | Financials NEW | Analysis | Options | Holders | Sustainability

Currency in USD

Earnings Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	4	4	3	5
Avg. Estimate	0.68	0.77	1.9	1.99
Low Estimate	0.63	0.71	1.87	1.88
High Estimate	0.72	0.83	1.92	2.07
Year Ago EPS	0.7	0.75	2.07	1.9

Revenue Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	3	2	3	3
Avg. Estimate	389.64M	402.35M	1.37B	1.44B
Low Estimate	370.91M	392.58M	1.35B	1.4B
High Estimate	418.2M	412.13M	1.39B	1.47B
Year Ago Sales	372.22M	414.66M	1.4B	1.37B
Sales Growth (year/est)	4.70%	-3.00%	-1.90%	5.10%

Earnings History	12/30/2018	3/30/2019	6/29/2019	9/29/2019
EPS Est.	0.65	0.83	0.36	0.14
EPS Actual	0.7	0.75	0.33	0.08
Difference	0.05	-0.08	-0.03	-0.06
Surprise %	7.70%	-9.60%	-8.30%	-42.90%

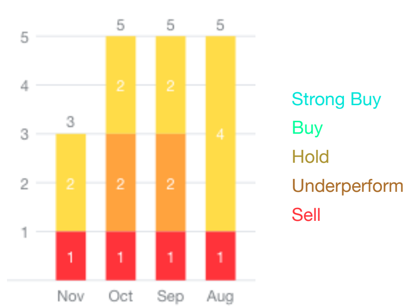
EPS Trend	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Current Estimate	0.68	0.77	1.9	1.99
7 Days Ago	0.68	0.77	1.9	1.99
30 Days Ago	0.67	0.77	1.92	1.99
60 Days Ago	0.67	0.77	1.92	2
90 Days Ago	0.67	0.77	1.91	2

EPS Revisions	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Up Last 7 Days	1	1	N/A	N/A

People Also Watch

Symbol	Last Price	Change	% Change
IDA IDACORP, Inc.	105.30	+0.73	+0.70%
BKH Black Hills Corporation	77.06	+0.05	+0.06%
ALE Allete, Inc.	79.57	-0.08	-0.10%
LNT Alliant Energy Corporation	53.40	+0.02	+0.04%
EE El Paso Electric Company	67.79	-0.14	-0.21%

Recommendation Trends >



Recommendation Rating >

3.8

Up Last 30 Days	1	1	1	2
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	1	1	3	1

Growth Estimates	AVA	Industry	Sector	S&P 500
Current Qtr.	-2.90%	N/A	N/A	0.02
Next Qtr.	2.70%	N/A	N/A	0.06
Current Year	-8.20%	N/A	N/A	-0.03
Next Year	4.70%	N/A	N/A	0.14
Next 5 Years (per annum)	3.40%	N/A	N/A	0.07
Past 5 Years (per annum)	-5.94%	N/A	N/A	N/A

1 Strong Buy	2 Buy	3 Hold	4 Under-perform	5 Sell

Analyst Price Targets (5) >

Average 43.40

Low 41.00 High 46.00 Current 46

Upgrades & Downgrades >

Maintains	KeyBanc: to Underweight	10/21/2019
↓ Downgrade	Williams Capital: Hold to Sell	9/16/2019
Initiated	Bank of America: to Underperform	5/9/2019

Yahoo Small Business

Black Hills Corporation (BKH)

NYSE - Nasdaq Real Time Price. Currency in USD

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Quote Lookup

77.08 +0.07 (+0.10%)

As of 12:33PM EST. Market open.

Buy Sell

Currency in USD

Earnings Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	5	2	6	7
Avg. Estimate	1.11	1.58	3.42	3.67
Low Estimate	1.04	1.56	3.23	3.6
High Estimate	1.24	1.6	3.5	3.71
Year Ago EPS	1.05	1.73	3.54	3.42

Revenue Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	3	1	3	5
Avg. Estimate	553.38M	653.31M	1.81B	2B
Low Estimate	516M	653.31M	1.77B	1.87B
High Estimate	592.68M	653.31M	1.85B	2.18B
Year Ago Sales	501.2M	597.8M	1.75B	1.81B
Sales Growth (year/est)	10.40%	9.30%	3.20%	10.50%

Earnings History	12/30/2018	3/30/2019	6/29/2019	9/29/2019
EPS Est.	0.92	1.56	0.43	0.45
EPS Actual	1.05	1.73	0.24	0.19
Difference	0.13	0.17	-0.19	-0.26
Surprise %	14.10%	10.90%	-44.20%	-57.80%

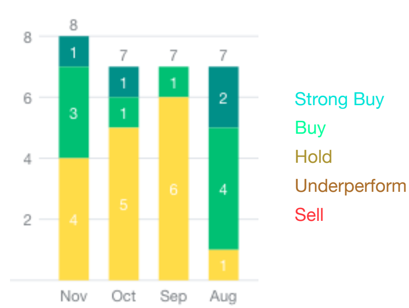
EPS Trend	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Current Estimate	1.11	1.58	3.42	3.67
7 Days Ago	1.11	1.58	3.42	3.67
30 Days Ago	1.04	1.6	3.46	3.68
60 Days Ago	1.02	1.6	3.46	3.68
90 Days Ago	1.02	1.6	3.46	3.68

EPS Revisions	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Up Last 7 Days	1	N/A	1	N/A

People Also Watch

Symbol	Last Price	Change	% Change
VVC 174877			
IDA IDACORP, Inc.	105.30	+0.73	+0.70%
ATO Atmos Energy Corporation	107.38	-0.08	-0.08%
WGL 197425			
MGEE MGE Energy Inc.	76.64	+0.69	+0.91%

Recommendation Trends ›



Recommendation Rating ›

Up Last 30 Days	4	N/A	1	2
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	1	1	N/A	1

Growth Estimates	BKH	Industry	Sector	S&P 500
Current Qtr.	5.70%	N/A	N/A	0.02
Next Qtr.	-8.70%	N/A	N/A	0.06
Current Year	-3.40%	N/A	N/A	-0.03
Next Year	7.30%	N/A	N/A	0.14
Next 5 Years (per annum)	3.66%	N/A	N/A	0.07
Past 5 Years (per annum)	-7.70%	N/A	N/A	N/A

1 Strong Buy	2 Buy	3 Hold	4 Under-perform	5 Sell

Analyst Price Targets (6) ›

Average 77.50

Low 64.00 High 88.00

Current 77.08

Upgrades & Downgrades ›

Maintains	Wells Fargo: to Market Perform	11/6/2019
Upgrade	Bank of America: Neutral to Buy	10/10/2019
Maintains	Credit Suisse: to Neutral	8/9/2019
Upgrade	Scotiabank: Underperform to Sector Perform	5/9/2019
Maintains	Credit Suisse: Neutral to Neutral	2/11/2019
Downgrade	Credit Suisse: Outperform to Neutral	1/23/2019

More Upgrades & Downgrades

Yahoo Small Business

CMS Energy Corporation (CMS)

NYSE - Nasdaq Real Time Price. Currency in USD

Add to watchlist | Visitors trend 2W↓ 10W↑ 9M↑ | Quote Lookup

61.71 -0.24 (-0.39%)

As of 12:36PM EST. Market open.

Buy Sell

Currency in USD

Earnings Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	10	6	16	17
Avg. Estimate	0.71	0.88	2.49	2.67
Low Estimate	0.67	0.76	2.48	2.59
High Estimate	0.82	0.98	2.5	2.69
Year Ago EPS	0.4	0.75	2.33	2.49

Revenue Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	6	3	9	10
Avg. Estimate	1.94B	2.04B	6.98B	7.16B
Low Estimate	1.89B	2B	6.89B	7.02B
High Estimate	2B	2.12B	7.08B	7.32B
Year Ago Sales	1.83B	2.06B	6.87B	6.98B
Sales Growth (year/est)	6.30%	-0.70%	1.50%	2.70%

Earnings History	12/30/2018	3/30/2019	6/29/2019	9/29/2019
EPS Est.	0.4	0.78	0.36	0.67
EPS Actual	0.4	0.75	0.33	0.73
Difference	0	-0.03	-0.03	0.06
Surprise %	0.00%	-3.80%	-8.30%	9.00%

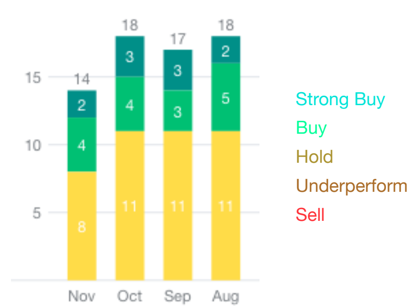
EPS Trend	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Current Estimate	0.71	0.88	2.49	2.67
7 Days Ago	0.71	0.88	2.49	2.67
30 Days Ago	0.76	0.87	2.5	2.68
60 Days Ago	0.64	0.89	2.5	2.68
90 Days Ago	0.64	0.89	2.5	2.68

EPS Revisions	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Up Last 7 Days	1	N/A	N/A	N/A

People Also Watch

Symbol	Last Price	Change	% Change
DTE DTE Energy Company	123.38	+0.01	+0.01%
CNP CenterPoint Energy, Inc (Holdin	24.98	+0.44	+1.79%
EIX Edison International	71.50	+0.49	+0.69%
AEE Ameren Corporation	75.05	-0.14	-0.19%
ETR Entergy Corporation	115.77	-0.13	-0.11%

Recommendation Trends >



Recommendation Rating >

2.4

Up Last 30 Days	3	2	2	2
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	N/A

Growth Estimates	CMS	Industry	Sector	S&P 500
Current Qtr.	77.50%	N/A	N/A	0.02
Next Qtr.	17.30%	N/A	N/A	0.06
Current Year	6.90%	N/A	N/A	-0.03
Next Year	7.20%	N/A	N/A	0.14
Next 5 Years (per annum)	7.50%	N/A	N/A	0.07
Past 5 Years (per annum)	7.18%	N/A	N/A	N/A

1 Strong Buy	2 Buy	3 Hold	4 Under-perform	5 Sell

Analyst Price Targets (15) ›

Average 65.77

Low 59.00 High 75.00

Current 61.71

Upgrades & Downgrades ›

Maintains	JP Morgan: to Overweight	10/14/2019
Maintains	SunTrust Robinson Humphrey: to Hold	9/30/2019
Maintains	UBS: to Neutral	9/6/2019
Maintains	Morgan Stanley: to Equal-Weight	9/6/2019
Maintains	Wells Fargo: to Outperform	8/26/2019
Maintains	Morgan Stanley: to Equal-Weight	8/16/2019

More Upgrades & Downgrades

Yahoo Small Business

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CenterPoint Energy, Inc. (CNP)

NYSE - Nasdaq Real Time Price. Currency in USD

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Quote Lookup

24.98 +0.44 (+1.79%)

As of 12:35PM EST. Market open.

Buy Sell

Currency in USD

Earnings Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	11	9	9	17
Avg. Estimate	0.37	0.5	1.68	1.74
Low Estimate	0.32	0.43	1.66	1.59
High Estimate	0.45	0.69	1.7	1.86
Year Ago EPS	0.36	0.46	1.6	1.68

Revenue Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	6	4	10	13
Avg. Estimate	3.74B	3.66B	13.03B	13.45B
Low Estimate	2.29B	3.46B	11.37B	11.82B
High Estimate	4.26B	3.78B	13.79B	14.45B
Year Ago Sales	3.04B	3.53B	10.59B	13.03B
Sales Growth (year/est)	23.10%	3.70%	23.00%	3.20%

Earnings History	12/30/2018	3/30/2019	6/29/2019	9/29/2019
EPS Est.	0.34	0.54	0.31	0.43
EPS Actual	0.36	0.46	0.35	0.53
Difference	0.02	-0.08	0.04	0.1
Surprise %	5.90%	-14.80%	12.90%	23.30%

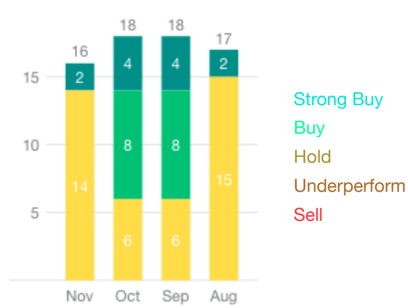
EPS Trend	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Current Estimate	0.37	0.5	1.68	1.74
7 Days Ago	0.37	0.5	1.68	1.74
30 Days Ago	0.41	0.54	1.64	1.77
60 Days Ago	0.42	0.54	1.64	1.78
90 Days Ago	0.42	0.55	1.64	1.79

EPS Revisions	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Up Last 7 Days	N/A	N/A	9	2

People Also Watch

Symbol	Last Price	Change	% Change
CMS CMS Energy Corporation	61.71	-0.24	-0.39%
FE FirstEnergy Corp.	47.24	+0.60	+1.29%
NI NiSource Inc	26.42	+0.20	+0.76%
ETR Entergy Corporation	115.77	-0.13	-0.11%
AEP American Electric Power Company	91.12	+0.05	+0.05%

Recommendation Trends ›



Recommendation Rating ›

2.2

Up Last 30 Days	2	N/A	10	2
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	5	5	N/A	8

Growth Estimates	CNP	Industry	Sector	S&P 500
Current Qtr.	2.80%	N/A	N/A	0.02
Next Qtr.	8.70%	N/A	N/A	0.06
Current Year	5.00%	N/A	N/A	-0.03
Next Year	3.60%	N/A	N/A	0.14
Next 5 Years (per annum)	4.10%	N/A	N/A	0.07
Past 5 Years (per annum)	10.26%	N/A	N/A	N/A

1 Strong Buy	2 Buy	3 Hold	4 Under-perform	5 Sell

Analyst Price Targets (15) >

Average 31.30

Low 28.00 High 35.00

Current 24.98

Upgrades & Downgrades >

Downgrade	Barclays: Overweight to Equal-Weight	11/21/2019
Maintains	Goldman Sachs: to Buy	11/18/2019
Maintains	Morgan Stanley: to Equal-Weight	11/18/2019
Downgrade	Credit Suisse: Outperform to Neutral	11/15/2019
Downgrade	SunTrust Robinson Humphrey: Buy to Hold	11/15/2019
Downgrade	Bank of America: Buy to Neutral	11/15/2019

More Upgrades & Downgrades

Yahoo Small Business

Chesapeake Utilities Corporation (CPK)

NYSE - Nasdaq Real Time Price. Currency in USD

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Quote Lookup

90.34 +0.99 (+1.11%)

As of 12:33PM EST. Market open.

Buy Sell

Currency in USD

Earnings Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	3	2	4	4
Avg. Estimate	1.17	1.59	3.72	3.98
Low Estimate	1.14	1.36	3.66	3.93
High Estimate	1.22	1.82	3.78	4.04
Year Ago EPS	1.1	1.68	3.31	3.72

Revenue Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	3	3	5	5
Avg. Estimate	215.73M	243.63M	719.33M	786.35M
Low Estimate	193.7M	223.9M	644.8M	678M
High Estimate	228.6M	258.4M	764.1M	949.2M
Year Ago Sales	201.19M	227.62M	717.49M	719.33M
Sales Growth (year/est)	7.20%	7.00%	0.30%	9.30%

Earnings History	12/30/2018	3/30/2019	6/29/2019	9/29/2019
EPS Est.	1.2	1.59	0.55	0.39
EPS Actual	1.1	1.68	0.5	0.34
Difference	-0.1	0.09	-0.05	-0.05
Surprise %	-8.30%	5.70%	-9.10%	-12.80%

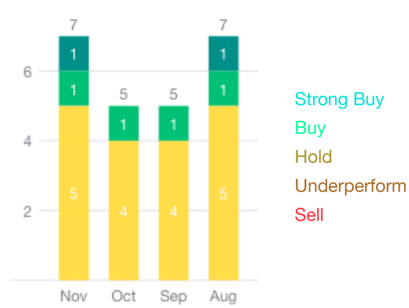
EPS Trend	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Current Estimate	1.17	1.59	3.72	3.98
7 Days Ago	1.17	1.59	3.72	3.98
30 Days Ago	1.14	1.53	3.72	3.97
60 Days Ago	1.1	1.51	3.74	3.97
90 Days Ago	1.1	1.51	3.74	3.97

EPS Revisions	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Up Last 7 Days	2	1	N/A	1

People Also Watch

Symbol	Last Price	Change	% Change
SJI South Jersey Industries, Inc.	30.50	+0.19	+0.63%
NJR NewJersey Resources Corporation	42.89	-0.07	-0.16%
RGCO RGC Resources Inc.	28.42	+0.30	+1.08%
SWX Southwest Gas Holdings, Inc.	75.93	+0.18	+0.24%
DGAS 3792			

Recommendation Trends >



Recommendation Rating >

Up Last 30 Days	2	1	N/A	1
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	1	N/A	N/A

Growth Estimates	CPK	Industry	Sector	S&P 500
Current Qtr.	6.40%	N/A	N/A	0.02
Next Qtr.	-5.40%	N/A	N/A	0.06
Current Year	12.40%	N/A	N/A	-0.03
Next Year	7.00%	N/A	N/A	0.14
Next 5 Years (per annum)	6.00%	N/A	N/A	0.07
Past 5 Years (per annum)	3.10%	N/A	N/A	N/A

1	2	3	4	5
Strong Buy	Buy	Hold	Under-perform	Sell

Analyst Price Targets (5) >

Average 101.00

Current 90.34 Low 92.00 High 110.00

Upgrades & Downgrades >

Maintains	Wells Fargo: to Market Perform	11/11/2019
Maintains	Wells Fargo: Market Perform to Market Perform	3/4/2019
Downgrade	Janney Capital: Buy to Neutral	12/17/2018
Initiated	Maxim Group: to Buy	11/28/2018
Upgrade	Janney Capital: Neutral to Buy	11/2/2018
Maintains	Wells Fargo: Market Perform to Market Perform	9/24/2018

More Upgrades & Downgrades

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Dominion Energy, Inc. (D)

NYSE - Nasdaq Real Time Price. Currency in USD

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83.04 +0.02 (+0.02%)

As of 12:37PM EST. Market open.

Buy Sell

Currency in USD

Earnings Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	8	3	11	11
Avg. Estimate	1.13	1.2	4.2	4.37
Low Estimate	1.05	1.08	4.11	4.14
High Estimate	1.22	1.4	4.28	4.45
Year Ago EPS	0.89	1.1	4.05	4.2

Revenue Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	4	1	5	7
Avg. Estimate	5.14B	5.06B	17.91B	19.16B
Low Estimate	4.25B	5.06B	17.07B	18.08B
High Estimate	6.59B	5.06B	18.69B	20.25B
Year Ago Sales	3.36B	3.86B	13.37B	17.91B
Sales Growth (year/est)	53.00%	31.30%	34.00%	7.00%

Earnings History	12/30/2018	3/30/2019	6/29/2019	9/29/2019
EPS Est.	0.9	1.11	0.76	1.14
EPS Actual	0.89	1.1	0.77	1.18
Difference	-0.01	-0.01	0.01	0.04
Surprise %	-1.10%	-0.90%	1.30%	3.50%

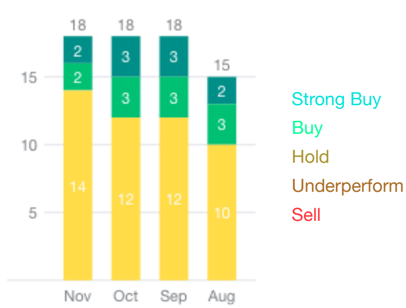
EPS Trend	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Current Estimate	1.13	1.2	4.2	4.37
7 Days Ago	1.13	1.2	4.2	4.37
30 Days Ago	1.17	1.09	4.19	4.38
60 Days Ago	1.16	1.16	4.18	4.39
90 Days Ago	1.16	1.16	4.17	4.39

EPS Revisions	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Up Last 7 Days	N/A	N/A	N/A	N/A

People Also Watch

Symbol	Last Price	Change	% Change
DUK Duke Energy Corporation (Holdin	86.85	+0.19	+0.22%
SO Southern Company (The)	62.82	+0.14	+0.22%
AEP American Electric Power Company	91.12	+0.05	+0.05%
ED Consolidated Edison, Inc.	85.89	-0.93	-1.07%
EXC Exelon Corporation	44.46	+0.07	+0.16%

Recommendation Trends >



Recommendation Rating >

2.5

Up Last 30 Days	2	N/A	6	4
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	1	N/A	1	N/A

Growth Estimates	D	Industry	Sector	S&P 500
Current Qtr.	27.00%	N/A	N/A	0.02
Next Qtr.	9.10%	N/A	N/A	0.06
Current Year	3.70%	N/A	N/A	-0.03
Next Year	4.00%	N/A	N/A	0.14
Next 5 Years (per annum)	4.46%	N/A	N/A	0.07
Past 5 Years (per annum)	3.37%	N/A	N/A	N/A

1 Strong Buy	2 Buy	3 Hold	4 Under-perform	5 Sell

Analyst Price Targets (15) >

Average 84.23

Low 76.00 High 92.00

Current 83.04

Upgrades & Downgrades >

Maintains	JP Morgan: to Neutral	11/5/2019
Maintains	Wells Fargo: to Market Perform	11/4/2019
Maintains	Morgan Stanley: to Equal-Weight	10/17/2019
Maintains	JP Morgan: to Neutral	10/14/2019
Upgrade	Bank of America: Underperform to Neutral	6/13/2019
Downgrade	Macquarie: Outperform to Neutral	3/18/2019

More Upgrades & Downgrades

Yahoo Small Business

DTE Energy Company (DTE)

NYSE - Nasdaq Real Time Price. Currency in USD

Add to watchlist | Visitors trend 2W ↓ 10W ↑ 9M ↑

Quote Lookup

123.28 -0.09 (-0.07%)

As of 12:37PM EST. Market open.

Buy Sell

Summary | Company Outlook | Chart | Conversations | Statistics | Historical Data | Profile | Financials NEW | Analysis | Options | Holders | Sustainability

Currency in USD

Earnings Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	10	5	14	14
Avg. Estimate	1.29	2.07	6.24	6.6
Low Estimate	1.16	1.73	6.17	6.36
High Estimate	1.41	2.3	6.4	6.76
Year Ago EPS	0.91	2.05	6.3	6.24

Revenue Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	5	2	7	8
Avg. Estimate	3.6B	3.45B	13.83B	14.28B
Low Estimate	3.07B	3.37B	13.02B	13.2B
High Estimate	3.98B	3.53B	15.06B	16.18B
Year Ago Sales	3.75B	3.8B	14.21B	13.83B
Sales Growth (year/est)	-3.90%	-9.10%	-2.70%	3.20%

Earnings History	12/30/2018	3/30/2019	6/29/2019	9/29/2019
EPS Est.	0.93	1.95	1.07	1.97
EPS Actual	0.91	2.05	0.99	1.91
Difference	-0.02	0.1	-0.08	-0.06
Surprise %	-2.20%	5.10%	-7.50%	-3.00%

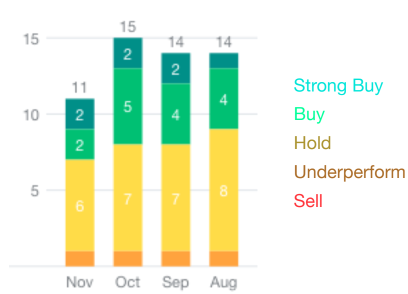
EPS Trend	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Current Estimate	1.29	2.07	6.24	6.6
7 Days Ago	1.29	2.07	6.24	6.6
30 Days Ago	1.24	2.09	6.25	6.6
60 Days Ago	1.19	2.14	6.25	6.58
90 Days Ago	1.19	2.14	6.24	6.58

EPS Revisions	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Up Last 7 Days	N/A	N/A	N/A	N/A

People Also Watch

Symbol	Last Price	Change	% Change
CMS CMS Energy Corporation	61.69	-0.26	-0.43%
ETR Entergy Corporation	115.73	-0.17	-0.15%
AEE Ameren Corporation	74.97	-0.22	-0.29%
FE FirstEnergy Corp.	47.19	+0.56	+1.19%
PNW Pinnacle West Capital Corporati	87.12	-0.15	-0.17%

Recommendation Trends ›



Recommendation Rating ›

Up Last 30 Days	5	2	2	7
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	N/A

Growth Estimates	DTE	Industry	Sector	S&P 500
Current Qtr.	41.80%	N/A	N/A	0.02
Next Qtr.	1.00%	N/A	N/A	0.06
Current Year	-1.00%	N/A	N/A	-0.03
Next Year	5.80%	N/A	N/A	0.14
Next 5 Years (per annum)	4.83%	N/A	N/A	0.07
Past 5 Years (per annum)	7.07%	N/A	N/A	N/A

1 Strong Buy	2 Buy	3 Hold	4 Under-perform	5 Sell

Analyst Price Targets (12) ›

Average 137.17

Low 127.00 High 145.00

Current 123.28

Upgrades & Downgrades ›

Upgrade	Bank of America: Underperform to Neutral	10/21/2019
Initiated	JP Morgan: to Neutral	10/8/2019
Upgrade	Mizuho: Neutral to Buy	10/7/2019
Upgrade	Wells Fargo: Market Perform to Outperform	8/26/2019
Initiated	Mizuho: to Neutral	8/12/2019
Maintains	Bank of America: to Underperform	6/3/2019

More Upgrades & Downgrades

Yahoo Small Business

Duke Energy Corporation (DUK)

NYSE - Nasdaq Real Time Price. Currency in USD

Add to watchlist | Visitors trend 2W ↓ 10W ↑ 9M ↑

Quote Lookup

86.81 +0.14 (+0.17%)

As of 12:38PM EST. Market open.

Buy Sell

Currency in USD

Earnings Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	10	4	12	12
Avg. Estimate	0.91	1.08	5.02	5.18
Low Estimate	0.81	0.75	4.95	5.07
High Estimate	0.97	1.27	5.12	5.27
Year Ago EPS	0.84	1.24	4.72	5.02

Revenue Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	5	2	6	7
Avg. Estimate	6.38B	6.3B	25.21B	26.26B
Low Estimate	6.12B	6.14B	24.37B	25.16B
High Estimate	6.76B	6.47B	25.91B	28.22B
Year Ago Sales	6.12B	6.32B	24.52B	25.21B
Sales Growth (year/est)	4.40%	-0.30%	2.80%	4.20%

Earnings History	12/30/2018	3/30/2019	6/29/2019	9/29/2019
EPS Est.	0.89	1.23	0.98	1.67
EPS Actual	0.84	1.24	1.12	1.79
Difference	-0.05	0.01	0.14	0.12
Surprise %	-5.60%	0.80%	14.30%	7.20%

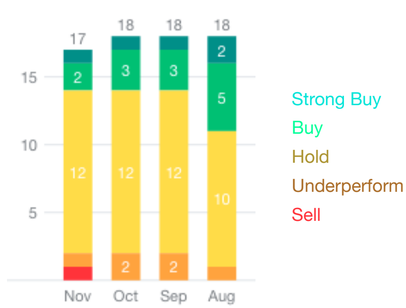
EPS Trend	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Current Estimate	0.91	1.08	5.02	5.18
7 Days Ago	0.91	1.08	5.02	5.18
30 Days Ago	0.92	1.16	4.96	5.15
60 Days Ago	0.93	1.17	4.98	5.17
90 Days Ago	0.93	1.17	4.96	5.17

EPS Revisions	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Up Last 7 Days	1	N/A	4	N/A

People Also Watch

Symbol	Last Price	Change	% Change
SO Southern Company (The)	62.80	+0.12	+0.19%
D Dominion Energy, Inc.	82.99	-0.03	-0.04%
AEP American Electric Power Company	91.07	-0.00	-0.01%
ED Consolidated Edison, Inc.	85.82	-1.00	-1.15%
SE Sea Limited	37.28	+0.06	+0.16%

Recommendation Trends >



Recommendation Rating >

2.8

Up Last 30 Days	1	N/A	4	N/A
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	4	1	N/A	6

Growth Estimates	DUK	Industry	Sector	S&P 500
Current Qtr.	8.30%	N/A	N/A	0.02
Next Qtr.	-12.90%	N/A	N/A	0.06
Current Year	6.40%	N/A	N/A	-0.03
Next Year	3.20%	N/A	N/A	0.14
Next 5 Years (per annum)	4.65%	N/A	N/A	0.07
Past 5 Years (per annum)	0.38%	N/A	N/A	N/A

1 Strong Buy | 2 Buy | 3 Hold | 4 Under-perform | 5 Sell

Analyst Price Targets (15) ›

Average 96.80

Low 88.00 High 105.00

Current 86.81

Upgrades & Downgrades ›

↑ Upgrade	Barclays: Equal-Weight to Overweight	11/21/2019
Maintains	Wells Fargo: to Market Perform	11/11/2019
Maintains	Morgan Stanley: to Equal-Weight	10/17/2019
Maintains	JP Morgan: to Neutral	10/14/2019
Maintains	Morgan Stanley: to Equal-Weight	9/25/2019
Maintains	Credit Suisse: to Neutral	9/9/2019

More Upgrades & Downgrades

Yahoo Small Business

Consolidated Edison, Inc. (ED)

NYSE - Nasdaq Real Time Price. Currency in USD

Add to watchlist | Visitors trend 2W ↓ 10W ↑ 9M ↑

Quote Lookup

85.89 -0.93 (-1.07%)

As of 12:36PM EST. Market open.

Buy Sell

Currency in USD

Earnings Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	11	6	15	17
Avg. Estimate	0.81	1.44	4.33	4.53
Low Estimate	0.76	1.29	4.27	4.44
High Estimate	0.87	1.5	4.38	4.62
Year Ago EPS	0.77	1.39	4.33	4.33

Revenue Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	5	2	8	10
Avg. Estimate	3.12B	3.66B	12.85B	13.34B
Low Estimate	3.04B	3.64B	12.67B	12.95B
High Estimate	3.42B	3.68B	13.43B	14.12B
Year Ago Sales	2.95B	3.51B	12.34B	12.85B
Sales Growth (year/est)	5.90%	4.20%	4.10%	3.80%

Earnings History	12/30/2018	3/30/2019	6/29/2019	9/29/2019
EPS Est.	0.75	1.36	0.59	1.58
EPS Actual	0.77	1.39	0.58	1.54
Difference	0.02	0.03	-0.01	-0.04
Surprise %	2.70%	2.20%	-1.70%	-2.50%

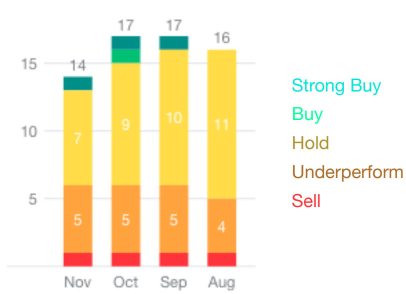
EPS Trend	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Current Estimate	0.81	1.44	4.33	4.53
7 Days Ago	0.81	1.44	4.33	4.53
30 Days Ago	0.81	1.45	4.35	4.56
60 Days Ago	0.78	1.45	4.35	4.57
90 Days Ago	0.77	1.45	4.35	4.58

EPS Revisions	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Up Last 7 Days	1	N/A	N/A	N/A

People Also Watch

Symbol	Last Price	Change	% Change
SO Southern Company (The)	62.82	+0.14	+0.22%
AEP American Electric Power Company	91.14	+0.07	+0.07%
DUK Duke Energy Corporation (Holdin	86.87	+0.21	+0.24%
D Dominion Energy, Inc.	83.08	+0.06	+0.07%
EXC Exelon Corporation	44.47	+0.08	+0.17%

Recommendation Trends ›



Recommendation Rating ›

3.2

Up Last 30 Days	6	N/A	1	3
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	1	1	2

Growth Estimates	ED	Industry	Sector	S&P 500
Current Qtr.	5.20%	N/A	N/A	0.02
Next Qtr.	3.60%	N/A	N/A	0.06
Current Year	N/A	N/A	N/A	-0.03
Next Year	4.60%	N/A	N/A	0.14
Next 5 Years (per annum)	2.78%	N/A	N/A	0.07
Past 5 Years (per annum)	1.62%	N/A	N/A	N/A

1 Strong Buy	2 Buy	3 Hold	4 Under-perform	5 Sell

Analyst Price Targets (16) ›

Average 91.38

Low 80.00 High 100.00

Current 85.89

Upgrades & Downgrades ›

↓ Downgrade	Barclays: Equal-Weight to Underweight	11/21/2019
Maintains	Credit Suisse: to Underperform	11/5/2019
Maintains	Wells Fargo: to Market Perform	11/5/2019
Maintains	Bank of America: to Buy	10/28/2019
↑ Upgrade	Mizuho: Neutral to Buy	10/25/2019
Maintains	KeyBanc: to Overweight	10/21/2019

More Upgrades & Downgrades

Yahoo Small Business

Exelon Corporation (EXC)

NasdaqGS - NasdaqGS Real Time Price. Currency in USD

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44.45 +0.06 (+0.14%)

As of 12:38PM EST. Market open.

Buy Sell

Currency in USD

Earnings Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	11	6	14	15
Avg. Estimate	0.75	0.88	3.13	3.09
Low Estimate	0.62	0.83	3.01	3.01
High Estimate	0.87	0.98	3.27	3.28
Year Ago EPS	0.58	0.87	3.12	3.13

Revenue Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	7	3	9	10
Avg. Estimate	8.19B	8.68B	33.97B	33.02B
Low Estimate	5.61B	6.83B	30.26B	25.98B
High Estimate	9.85B	9.7B	36.02B	35.96B
Year Ago Sales	8.81B	9.12B	35.98B	33.97B
Sales Growth (year/est)	-7.10%	-4.90%	-5.60%	-2.80%

Earnings History	12/30/2018	3/30/2019	6/29/2019	9/29/2019
EPS Est.	0.57	0.87	0.61	0.89
EPS Actual	0.58	0.87	0.6	0.92
Difference	0.01	0	-0.01	0.03
Surprise %	1.80%	0.00%	-1.60%	3.40%

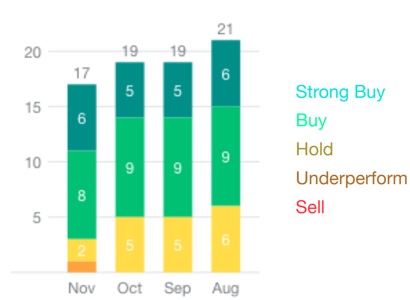
EPS Trend	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Current Estimate	0.75	0.88	3.13	3.09
7 Days Ago	0.75	0.88	3.13	3.09
30 Days Ago	0.78	0.9	3.14	3.1
60 Days Ago	0.78	0.88	3.14	3.08
90 Days Ago	0.78	0.89	3.13	3.07

EPS Revisions	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Up Last 7 Days	N/A	N/A	N/A	N/A

People Also Watch

Symbol	Last Price	Change	% Change
FE FirstEnergy Corp.	47.20	+0.56	+1.20%
ETR Entergy Corporation	115.72	-0.18	-0.16%
AEP American Electric Power Company	91.06	-0.01	-0.01%
D Dominion Energy, Inc.	82.99	-0.03	-0.04%
SO Southern Company (The)	62.80	+0.12	+0.19%

Recommendation Trends ›



Recommendation Rating ›

2

Up Last 30 Days	2	1	5	3
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	1	N/A	2	1

Growth Estimates	EXC	Industry	Sector	S&P 500
Current Qtr.	29.30%	N/A	N/A	0.02
Next Qtr.	1.10%	N/A	N/A	0.06
Current Year	0.30%	N/A	N/A	-0.03
Next Year	-1.30%	N/A	N/A	0.14
Next 5 Years (per annum)	-2.67%	N/A	N/A	0.07
Past 5 Years (per annum)	5.11%	N/A	N/A	N/A

1 Strong Buy	2 Buy	3 Hold	4 Under-perform	5 Sell

Analyst Price Targets (16) ›

Average 52.72

Low 45.00 High 62.00

Current 44.45

Upgrades & Downgrades ›

Maintains	Credit Suisse: to Outperform	10/18/2019
Maintains	Mizuho: to Neutral	10/16/2019
Maintains	UBS: to Buy	9/6/2019
↑ Upgrade	Morgan Stanley: Equal-Weight to Overweight	8/27/2019
Maintains	Morgan Stanley: to Equal-Weight	8/16/2019
↑ Upgrade	Barclays: Equal-Weight to Overweight	8/13/2019

More Upgrades & Downgrades

Yahoo Small Business

Fortis Inc. (FTS)

NYSE - Nasdaq Real Time Price. Currency in USD

Add to watchlist | Visitors trend 2W ↓ 10W ↑ 9M ↑ | Quote Lookup

39.74 -0.16 (-0.40%)

As of 12:36PM EST. Market open.

Buy Sell

Currency in USD

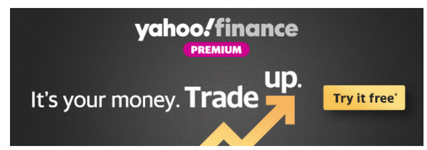
Earnings Estimate	Current Qtr. (Dec 2017)	Next Qtr. (Mar 2018)	Current Year (2017)	Next Year (2018)
No. of Analysts	1	0	1	1
Avg. Estimate	0.58	0	2.5	2.6
Low Estimate	0.58	0	2.5	2.6
High Estimate	0.58	0	2.5	2.6
Year Ago EPS	N/A	N/A	N/A	2.5

Revenue Estimate	Current Qtr. (Dec 2017)	Next Qtr. (Mar 2018)	Current Year (2017)	Next Year (2018)
No. of Analysts	0	0	1	1
Avg. Estimate	N/A	N/A	8.31B	8.52B
Low Estimate	N/A	N/A	8.31B	8.52B
High Estimate	N/A	N/A	8.31B	8.52B
Year Ago Sales	N/A	N/A	N/A	8.31B
Sales Growth (year/est)	N/A	N/A	N/A	2.50%

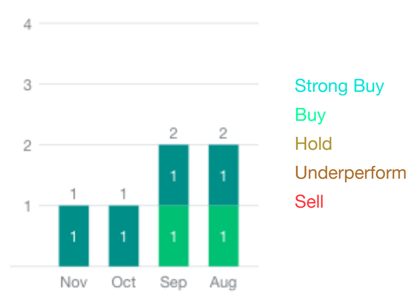
Earnings History	Invalid Date	Invalid Date	6/29/2017	9/29/2017
EPS Est.	N/A	N/A	0.49	0.59
EPS Actual	N/A	N/A	0.5	0.5
Difference	N/A	N/A	0.01	-0.09
Surprise %	N/A	N/A	2.00%	-15.30%

EPS Trend	Current Qtr. (Dec 2017)	Next Qtr. (Mar 2018)	Current Year (2017)	Next Year (2018)
Current Estimate	0.58	0	2.5	2.6
7 Days Ago	0.57	0	2.49	2.59
30 Days Ago	0.57	0	2.49	2.59
60 Days Ago	0.57	0	2.5	2.6
90 Days Ago	0.6	0	2.43	2.54

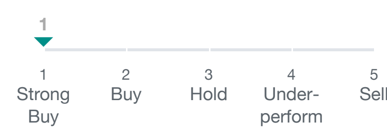
EPS Revisions	Current Qtr. (Dec 2017)	Next Qtr. (Mar 2018)	Current Year (2017)	Next Year (2018)
Up Last 7 Days	N/A	N/A	N/A	N/A



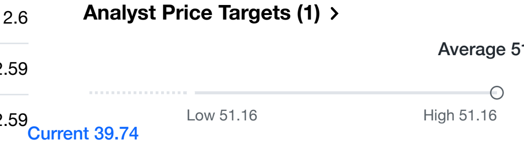
Recommendation Trends ›



Recommendation Rating ›



Analyst Price Targets (1) ›



Upgrades & Downgrades ›

↓ Downgrade	CIBC: Outperformer to Neutral	8/22/2019
↓ Downgrade	TD Securities: Buy to Hold	1/29/2019

Up Last 30 Days	N/A	N/A	N/A	N/A
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	N/A

Growth Estimates	FTS	Industry	Sector	S&P 500
Current Qtr.	N/A	N/A	N/A	0.02
Next Qtr.	N/A	N/A	N/A	0.06
Current Year	N/A	N/A	N/A	-0.03
Next Year	4.00%	N/A	N/A	0.14
Next 5 Years (per annum)	N/A	N/A	N/A	0.07
Past 5 Years (per annum)	N/A	N/A	N/A	N/A

Yahoo Small Business

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52.79 +0.39 (+0.74%)

At close: December 6 3:59PM EST

Currency in CAD

Earnings Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	13	5	13	15
Avg. Estimate	0.61	0.73	2.54	2.7
Low Estimate	0.58	0.69	2.49	2.51
High Estimate	0.65	0.78	2.63	2.87
Year Ago EPS	0.56	0.74	2.51	2.54

Revenue Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	6	3	10	11
Avg. Estimate	2.28B	2.52B	8.89B	9.41B
Low Estimate	2.24B	2.5B	8.7B	8.89B
High Estimate	2.35B	2.56B	9.42B	10.11B
Year Ago Sales	2.21B	2.44B	8.39B	8.89B
Sales Growth (year/est)	3.50%	3.60%	5.90%	5.80%

Earnings History	12/30/2018	3/30/2019	6/29/2019	9/29/2019
EPS Est.	0.61	0.73	0.57	0.66
EPS Actual	0.56	0.74	0.54	0.66
Difference	-0.05	0.01	-0.03	0
Surprise %	-8.20%	1.40%	-5.30%	0.00%

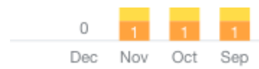
EPS Trend	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
7 Days Ago	0.64	0.75	2.55	2.75
30 Days Ago	0.65	0.74	2.56	2.8
60 Days Ago	0.62	0.73	2.56	2.79
90 Days Ago	0.61	0.73	2.57	2.77

People Also Watch

Symbol	Last Price	Change	% Change
EMA.TO EMERA INCORPORATED	55.34	+0.30	+0.55%
ENB.TO ENBRIDGE INC	51.10	+0.37	+0.73%
TRP.TO TC ENERGY CORP.	67.35	+0.51	+0.76%
T.TO TELUS CORPORATION	51.25	+0.39	+0.77%
BCE.TO BCE INC.	64.57	+0.54	+0.84%

EPS Revisions	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Up Last 7 Days	1	N/A	1	N/A
Up Last 30 Days	2	1	2	1
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	6	3	5	9

Growth Estimates	FTS.TO	Industry	Sector	S&P 500
Current Qtr.	8.90%	N/A	N/A	0.01
Next Qtr.	-1.40%	N/A	N/A	0.06
Current Year	1.20%	N/A	N/A	-0.03
Next Year	6.30%	N/A	N/A	0.14
Next 5 Years (per annum)	4.32%	N/A	N/A	0.07
Past 5 Years (per annum)	17.84%	N/A	N/A	N/A



Recommendation Rating ›

2.5

1 Strong Buy | 2 Buy | 3 Hold | 4 Under-perform | 5 Sell

Analyst Price Targets (14) ›

Average 56.64

Low 54.00 | Current 52.79 | High 61.00

Upgrades & Downgrades ›

Reiterates	Wells Fargo: to Outperform	11/22/2019
↓ Downgrade	CIBC: Outperformer to Neutral	8/22/2019
↓ Downgrade	TD Securities: Buy to Hold	1/29/2019

Earnings Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	5	3	7	9
Avg. Estimate	0.44	0.56	2.31	2.41
Low Estimate	0.43	0.53	2.3	2.37
High Estimate	0.45	0.6	2.33	2.46
Year Ago EPS	0.36	0.53	2.17	2.31

Revenue Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	1	1	4	5
Avg. Estimate	938.16M	867.06M	3.64B	3.82B
Low Estimate	938.16M	867.06M	3.52B	3.62B
High Estimate	938.16M	867.06M	3.71B	3.99B
Year Ago Sales	873.5M	N/A	3.53B	3.64B
Sales Growth (year/est)	7.40%	N/A	3.00%	5.00%

Earnings History	12/30/2018	3/30/2019	6/29/2019	9/29/2019
EPS Est.	0.35	0.51	0.44	0.93
EPS Actual	0.36	0.53	0.4	0.94
Difference	0.01	0.02	-0.04	0.01
Surprise %	2.90%	3.90%	-9.10%	1.10%

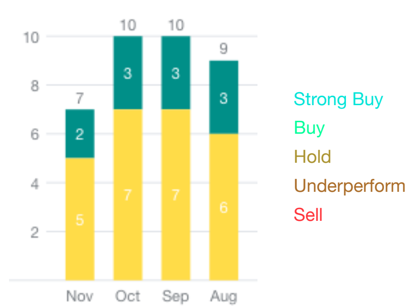
EPS Trend	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Current Estimate	0.44	0.56	2.31	2.41
7 Days Ago	0.44	0.56	2.31	2.41
30 Days Ago	0.41	0.56	2.26	2.41
60 Days Ago	0.43	0.57	2.26	2.42
90 Days Ago	0.43	0.56	2.26	2.42

EPS Revisions	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Up Last 7 Days	3	N/A	4	2

People Also Watch

Symbol	Last Price	Change	% Change
WEC WEC Energy Group, Inc.	88.34	+0.01	+0.01%
PNW Pinnacle West Capital Corporati	87.19	-0.08	-0.09%
CMS CMS Energy Corporation	61.71	-0.24	-0.39%
OGE OGE Energy Corp	41.98	-0.24	-0.57%
XEL Xcel Energy Inc.	61.12	-0.58	-0.94%

Recommendation Trends >



Recommendation Rating >

Up Last 30 Days	4	N/A	7	3
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	N/A

Growth Estimates	LNT	Industry	Sector	S&P 500
Current Qtr.	22.20%	N/A	N/A	0.02
Next Qtr.	5.70%	N/A	N/A	0.06
Current Year	6.50%	N/A	N/A	-0.03
Next Year	4.30%	N/A	N/A	0.14
Next 5 Years (per annum)	5.00%	N/A	N/A	0.07
Past 5 Years (per annum)	8.33%	N/A	N/A	N/A

1 Strong Buy	2 Buy	3 Hold	4 Under-perform	5 Sell

Analyst Price Targets (8) >

Average 51.50

Low 42.00 High 56.00
Current 53.40

Upgrades & Downgrades >

↑ Upgrade	Barclays: Equal-Weight to Overweight	11/21/2019
Maintains	UBS: to Neutral	9/6/2019
↑ Upgrade	Bank of America: Neutral to Buy	6/26/2019
Maintains	Wells Fargo: Outperform to Outperform	2/25/2019
↑ Upgrade	Wells Fargo: Market Perform to Outperform	1/30/2019
Initiated	Barclays: to Equal-Weight	1/18/2019

More Upgrades & Downgrades

Yahoo Small Business

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MGE Energy, Inc. (MGEE)

NasdaqGS - NasdaqGS Real Time Price. Currency in USD

Add to watchlist | Visitors trend 2W ↑ 10W ↑ 9M ↑ | Quote Lookup

76.64 +0.69 (+0.91%)

As of 12:31PM EST. Market open.

Buy Sell

Summary | Company Outlook | Chart | Conversations | Statistics | Historical Data | Profile | Financials NEW | Analysis | Options | Holders | Sustainability

Currency in USD

Earnings Estimate	Current Qtr.	Next Qtr.	Current Year	Next Year
No. of Analysts	0	0	0	0
Avg. Estimate	0	0	0	0
Low Estimate	0	0	0	0
High Estimate	0	0	0	0
Year Ago EPS	N/A	N/A	N/A	N/A

Revenue Estimate	Current Qtr.	Next Qtr.	Current Year	Next Year
No. of Analysts	0	0	0	0
Avg. Estimate	N/A	N/A	N/A	N/A
Low Estimate	N/A	N/A	N/A	N/A
High Estimate	N/A	N/A	N/A	N/A
Year Ago Sales	N/A	N/A	N/A	N/A
Sales Growth (year/est)	N/A	N/A	N/A	N/A

Earnings History	Invalid Date	Invalid Date	Invalid Date	Invalid Date
EPS Est.	N/A	N/A	N/A	N/A
EPS Actual	N/A	N/A	N/A	N/A
Difference	N/A	N/A	N/A	N/A
Surprise %	N/A	N/A	N/A	N/A

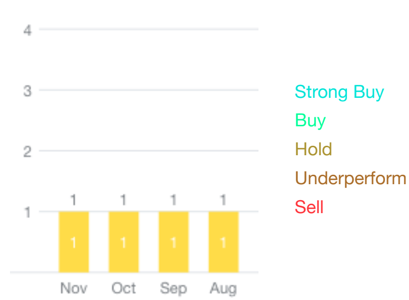
EPS Trend	Current Qtr.	Next Qtr.	Current Year	Next Year
Current Estimate	0	0	0	0
7 Days Ago	0	0	0	0
30 Days Ago	0	0	0	0
60 Days Ago	0	0	0	0
90 Days Ago	0	0	0	0

EPS Revisions	Current Qtr.	Next Qtr.	Current Year	Next Year
Up Last 7 Days	N/A	N/A	N/A	N/A

People Also Watch

Symbol	Last Price	Change	% Change
MSEX Middlesex Water Company	61.57	-0.82	-1.31%
BKH Black Hills Corporation	76.99	-0.02	-0.03%
CTWS Connecticut Water Service, Inc.	69.98	-0.01	-0.01%
NWN Northwest Natural Holding Compa	66.71	+0.24	+0.35%
WGL 197425			

Recommendation Trends >



Analyst Price Targets (1) >

Low 50.00 High 50.00

Up Last 30 Days	N/A	N/A	N/A	N/A
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	N/A

Growth Estimates	MGEE	Industry	Sector	S&P 500
Current Qtr.	N/A	N/A	N/A	0.02
Next Qtr.	N/A	N/A	N/A	0.06
Current Year	N/A	N/A	N/A	-0.03
Next Year	N/A	N/A	N/A	0.14
Next 5 Years (per annum)	4.00%	N/A	N/A	0.07
Past 5 Years (per annum)	N/A	N/A	N/A	N/A

NorthWestern Corporation (NWE)

NYSE - Nasdaq Real Time Price. Currency in USD

Add to watchlist | Visitors trend 2W ↑ 10W ↑ 9M ↑

Quote Lookup

70.97 +0.11 (+0.16%)

As of 12:33PM EST. Market open.

Buy | Sell

Currency in USD

Earnings Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	5	4	3	5
Avg. Estimate	1.17	1.32	3.42	3.56
Low Estimate	1.13	1.23	3.4	3.45
High Estimate	1.21	1.49	3.44	3.65
Year Ago EPS	1.07	1.23	3.39	3.42

Revenue Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	2	2	4	4
Avg. Estimate	306.13M	383.72M	1.23B	1.25B
Low Estimate	288.17M	378.7M	1.22B	1.23B
High Estimate	324.1M	388.75M	1.25B	1.28B
Year Ago Sales	308.82M	384.22M	1.19B	1.23B
Sales Growth (year/est)	-0.90%	-0.10%	3.10%	1.90%

Earnings History	12/30/2018	3/30/2019	6/29/2019	9/29/2019
EPS Est.	1	1.2	0.58	0.53
EPS Actual	1.07	1.23	0.5	0.5
Difference	0.07	0.03	-0.08	-0.03
Surprise %	7.00%	2.50%	-13.80%	-5.70%

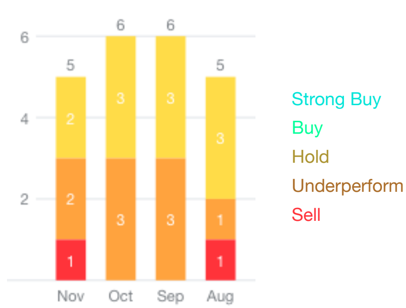
EPS Trend	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Current Estimate	1.17	1.32	3.42	3.56
7 Days Ago	1.17	1.32	3.42	3.56
30 Days Ago	1.2	1.32	3.5	3.6
60 Days Ago	0.95	1.33	3.52	3.6
90 Days Ago	0.95	1.33	3.52	3.6

EPS Revisions	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Up Last 7 Days	N/A	N/A	N/A	N/A

People Also Watch

Symbol	Last Price	Change	% Change
POR Portland General Electric Co	55.39	-0.14	-0.25%
PNM PNM Resources, Inc. (Holding Co	48.59	-0.34	-0.69%
NJR NewJersey Resources Corporation	42.87	-0.09	-0.21%
BKH Black Hills Corporation	76.99	-0.02	-0.03%
UTL UNITIL Corporation	60.66	+0.16	+0.26%

Recommendation Trends >



Recommendation Rating >

3.5

Up Last 30 Days	3	1	2	1
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	N/A

Growth Estimates	NWE	Industry	Sector	S&P 500
Current Qtr.	9.30%	N/A	N/A	0.02
Next Qtr.	7.30%	N/A	N/A	0.06
Current Year	0.90%	N/A	N/A	-0.03
Next Year	4.10%	N/A	N/A	0.14
Next 5 Years (per annum)	3.20%	N/A	N/A	0.07
Past 5 Years (per annum)	3.94%	N/A	N/A	N/A

1 Strong Buy	2 Buy	3 Hold	4 Under-perform	5 Sell

Analyst Price Targets (6) ›

Average 73.00

Low 67.00 High 79.00

Current 70.97

Upgrades & Downgrades ›

Maintains	Credit Suisse: to Underperform	11/4/2019
Upgrade	Williams Capital: Sell to Hold	8/26/2019
Downgrade	Barclays: Equal-Weight to Underweight	3/20/2019
Maintains	Credit Suisse: Underperform to Underperform	2/13/2019
Maintains	KeyBanc: Overweight to Overweight	12/17/2018
Maintains	Barclays: Equal-Weight to Equal-Weight	11/19/2018

More Upgrades & Downgrades

Yahoo Small Business

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Public Service Enterprise Group Incorporated (PEG)

NYSE - Nasdaq Real Time Price. Currency in USD

Add to watchlist | Visitors trend 2W ↑ 10W ↑ 9M ↑

Quote Lookup

60.24 -0.48 (-0.78%)

Buy Sell

As of 12:39PM EST. Market open.

Currency in USD

Earnings Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	8	5	14	14
Avg. Estimate	0.62	1.11	3.24	3.41
Low Estimate	0.58	1	3.17	3.27
High Estimate	0.64	1.31	3.26	3.52
Year Ago EPS	0.56	1.08	3.12	3.24

Revenue Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	3	2	8	10
Avg. Estimate	2.69B	3.71B	10.13B	10.63B
Low Estimate	2.25B	3.53B	9.69B	9.13B
High Estimate	2.96B	3.89B	10.56B	12.23B
Year Ago Sales	2.47B	2.98B	9.7B	10.13B
Sales Growth (year/est)	9.00%	24.50%	4.50%	4.90%

Earnings History	12/30/2018	3/30/2019	6/29/2019	9/29/2019
EPS Est.	0.55	1	0.6	0.96
EPS Actual	0.56	1.08	0.58	0.98
Difference	0.01	0.08	-0.02	0.02
Surprise %	1.80%	8.00%	-3.30%	2.10%

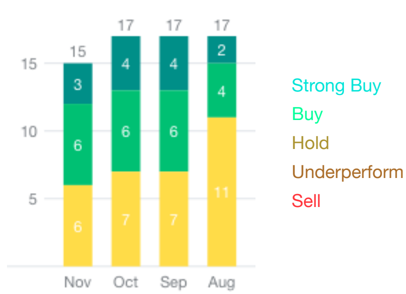
EPS Trend	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Current Estimate	0.62	1.11	3.24	3.41
7 Days Ago	0.62	1.11	3.24	3.41
30 Days Ago	0.63	1.12	3.24	3.42
60 Days Ago	0.64	1.1	3.24	3.41
90 Days Ago	0.65	1.1	3.24	3.41

EPS Revisions	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Up Last 7 Days	N/A	N/A	1	N/A

People Also Watch

Symbol	Last Price	Change	% Change
PPL PPL Corporation	33.74	+0.08	+0.22%
FE FirstEnergy Corp.	47.20	+0.56	+1.20%
PNW Pinnacle West Capital Corporati	87.04	-0.23	-0.27%
ETR Entergy Corporation	115.73	-0.17	-0.15%
NI NiSource Inc	26.37	+0.15	+0.57%

Recommendation Trends ›



Recommendation Rating ›

2.3

Up Last 30 Days	3	1	8	5
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	1	N/A	1	1

Growth Estimates	PEG	Industry	Sector	S&P 500
Current Qtr.	10.70%	N/A	N/A	0.02
Next Qtr.	2.80%	N/A	N/A	0.06
Current Year	3.80%	N/A	N/A	-0.03
Next Year	5.20%	N/A	N/A	0.14
Next 5 Years (per annum)	3.70%	N/A	N/A	0.07
Past 5 Years (per annum)	3.50%	N/A	N/A	N/A

1 Strong Buy	2 Buy	3 Hold	4 Under-perform	5 Sell

Analyst Price Targets (14) ›

Average 65.57

Low 61.00 High 71.00

Current 60.25

Upgrades & Downgrades ›

Downgrade	Barclays: Overweight to Equal-Weight	11/21/2019
Maintains	Mizuho: to Buy	10/23/2019
Maintains	RBC Capital: to Sector Perform	10/3/2019
Maintains	UBS: to Buy	9/6/2019
Maintains	Mizuho: to Buy	9/3/2019
Initiated	Barclays: to Overweight	8/13/2019

More Upgrades & Downgrades

Yahoo Small Business

Sempra Energy (SRE)

NYSE - Nasdaq Real Time Price. Currency in USD

Add to watchlist | Visitors trend 2W ↓ 10W ↑ 9M ↑

Quote Lookup

147.25 +0.45 (+0.31%)

As of 12:40PM EST. Market open.

Buy Sell

Currency in USD

Earnings Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	10	6	15	15
Avg. Estimate	1.5	1.89	6.13	7.12
Low Estimate	1.03	1.54	5.89	6.37
High Estimate	1.7	2.27	6.35	7.82
Year Ago EPS	1.56	1.92	5.57	6.13

Revenue Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	5	2	9	9
Avg. Estimate	3.68B	3.5B	11.78B	12.1B
Low Estimate	3.04B	3.22B	10.93B	10.99B
High Estimate	4.85B	3.77B	12.73B	13.44B
Year Ago Sales	3.22B	2.9B	11.69B	11.78B
Sales Growth (year/est)	14.20%	20.70%	0.80%	2.70%

Earnings History	12/30/2018	3/30/2019	6/29/2019	9/29/2019
EPS Est.	1.46	1.68	1.16	1.47
EPS Actual	1.56	1.92	1.1	1.5
Difference	0.1	0.24	-0.06	0.03
Surprise %	6.80%	14.30%	-5.20%	2.00%

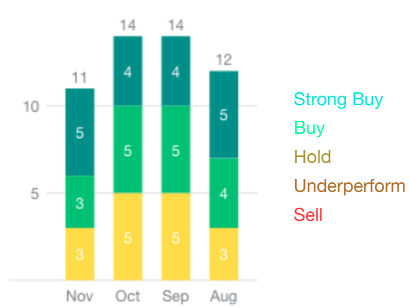
EPS Trend	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Current Estimate	1.5	1.89	6.13	7.12
7 Days Ago	1.5	1.89	6.13	7.12
30 Days Ago	1.58	1.85	6.09	7.04
60 Days Ago	1.59	1.83	6.01	7.01
90 Days Ago	1.59	1.82	6.02	7.01

EPS Revisions	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Up Last 7 Days	N/A	N/A	1	1

People Also Watch

Symbol	Last Price	Change	% Change
EIX Edison International	71.31	+0.30	+0.42%
XEL Xcel Energy Inc.	61.13	-0.58	-0.93%
PEG Public Service Enterprise Group	60.24	-0.48	-0.78%
PNW Pinnacle West Capital Corporati	87.05	-0.22	-0.25%
WEC WEC Energy Group, Inc.	88.26	-0.07	-0.08%

Recommendation Trends ›



Recommendation Rating ›

2.1

Up Last 30 Days	3	3	7	6
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	1	N/A	1	N/A

Growth Estimates	SRE	Industry	Sector	S&P 500
Current Qtr.	-3.80%	N/A	N/A	0.02
Next Qtr.	-1.60%	N/A	N/A	0.06
Current Year	10.10%	N/A	N/A	-0.03
Next Year	16.20%	N/A	N/A	0.14
Next 5 Years (per annum)	9.75%	N/A	N/A	0.07
Past 5 Years (per annum)	3.17%	N/A	N/A	N/A

1 Strong Buy	2 Buy	3 Hold	4 Under-perform	5 Sell

Analyst Price Targets (14) ›

Average 155.71

Low 144.00 High 165.00
Current 147.25

Upgrades & Downgrades ›

Maintains	Morgan Stanley: to Equal-Weight	11/8/2019
Maintains	Morgan Stanley: to Equal-Weight	10/17/2019
Maintains	JP Morgan: to Neutral	10/14/2019
Maintains	Morgan Stanley: to Equal-Weight	10/1/2019
Maintains	Wells Fargo: to Outperform	9/30/2019
Maintains	Argus Research: to Buy	9/24/2019

More Upgrades & Downgrades

Yahoo Small Business

WEC Energy Group, Inc. (WEC)

NYSE - Nasdaq Real Time Price. Currency in USD

Add to watchlist | Visitors trend 2W ↓ 10W ↑ 9M ↑ | Quote Lookup

88.26 -0.07 (-0.08%)

As of 12:40PM EST. Market open.

Buy Sell

Currency in USD

Earnings Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	11	4	15	15
Avg. Estimate	0.73	1.25	3.53	3.75
Low Estimate	0.71	1.06	3.52	3.72
High Estimate	0.78	1.38	3.54	3.81
Year Ago EPS	0.65	1.33	3.34	3.53

Revenue Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	6	2	8	8
Avg. Estimate	2.21B	2.35B	7.86B	8.16B
Low Estimate	1.93B	2.24B	7.2B	7.65B
High Estimate	2.71B	2.45B	8.29B	8.65B
Year Ago Sales	2.08B	2.35B	7.68B	7.86B
Sales Growth (year/est)	6.60%	-0.00%	2.30%	3.90%

Earnings History	12/30/2018	3/30/2019	6/29/2019	9/29/2019
EPS Est.	0.63	1.25	0.7	0.71
EPS Actual	0.65	1.33	0.74	0.74
Difference	0.02	0.08	0.04	0.03
Surprise %	3.20%	6.40%	5.70%	4.20%

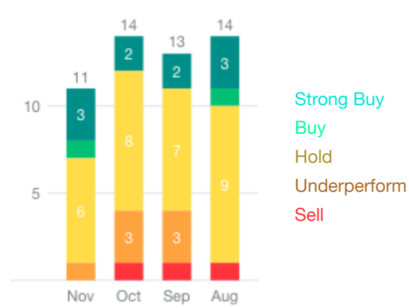
EPS Trend	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Current Estimate	0.73	1.25	3.53	3.75
7 Days Ago	0.73	1.25	3.53	3.75
30 Days Ago	0.74	1.33	3.53	3.76
60 Days Ago	0.74	1.33	3.53	3.75
90 Days Ago	0.75	1.32	3.52	3.74

EPS Revisions	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Up Last 7 Days	N/A	N/A	1	N/A

People Also Watch

Symbol	Last Price	Change	% Change
LNT Alliant Energy Corporation	53.35	-0.03	-0.06%
XEL Xcel Energy Inc.	61.13	-0.57	-0.92%
SCG 348714			
CMS CMS Energy Corporation	61.72	-0.23	-0.37%
PNW Pinnacle West Capital Corporati	87.05	-0.22	-0.25%

Recommendation Trends >



Recommendation Rating >

Up Last 30 Days	2	N/A	5	2
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	4	1	1	2

Growth Estimates	WEC	Industry	Sector	S&P 500
Current Qtr.	12.30%	N/A	N/A	0.02
Next Qtr.	-6.00%	N/A	N/A	0.06
Current Year	5.70%	N/A	N/A	-0.03
Next Year	6.20%	N/A	N/A	0.14
Next 5 Years (per annum)	6.15%	N/A	N/A	0.07
Past 5 Years (per annum)	6.98%	N/A	N/A	N/A

1	2	3	4	5
Strong Buy	Buy	Hold	Under-perform	Sell

Analyst Price Targets (12) ›

Average 90.33

Low 78.00 High 103.00

Current 88.26

Upgrades & Downgrades ›

Maintains	Credit Suisse: to Underperform	11/13/2019
Maintains	Citigroup: to Neutral	10/30/2019
Initiated	JP Morgan: to Neutral	10/8/2019
Maintains	UBS: to Neutral	9/6/2019
Downgrade	Guggenheim: Buy to Neutral	9/4/2019
Maintains	Wells Fargo: to Outperform	8/27/2019

More Upgrades & Downgrades

Xcel Energy Inc. (XEL)

NasdaqGS - NasdaqGS Real Time Price. Currency in USD

Add to watchlist | Visitors trend 2W ↑ 10W ↑ 9M ↑ | Quote Lookup

61.14 -0.56 (-0.91%)

As of 12:41PM EST. Market open.

Buy Sell

Currency in USD

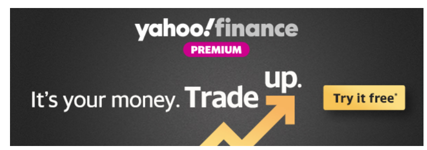
Earnings Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	7	2	12	12
Avg. Estimate	0.53	0.63	2.62	2.78
Low Estimate	0.49	0.62	2.6	2.73
High Estimate	0.55	0.65	2.66	2.82
Year Ago EPS	0.42	0.61	2.47	2.62

Revenue Estimate	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
No. of Analysts	5	1	9	9
Avg. Estimate	3.03B	3.22B	11.88B	12.39B
Low Estimate	2.94B	3.22B	11.71B	12.04B
High Estimate	3.18B	3.22B	12.28B	12.97B
Year Ago Sales	2.88B	3.04B	11.54B	11.88B
Sales Growth (year/est)	5.30%	6.10%	2.90%	4.30%

Earnings History	12/30/2018	3/30/2019	6/29/2019	9/29/2019
EPS Est.	0.42	0.62	0.51	1.03
EPS Actual	0.42	0.61	0.46	1.01
Difference	0	-0.01	-0.05	-0.02
Surprise %	0.00%	-1.60%	-9.80%	-1.90%

EPS Trend	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Current Estimate	0.53	0.63	2.62	2.78
7 Days Ago	0.53	0.63	2.62	2.78
30 Days Ago	0.51	0.63	2.62	2.79
60 Days Ago	0.49	0.64	2.61	2.8
90 Days Ago	0.49	0.64	2.62	2.8

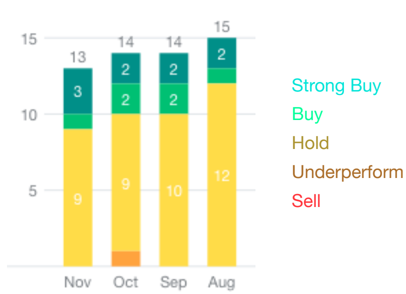
EPS Revisions	Current Qtr. (Dec 2019)	Next Qtr. (Mar 2020)	Current Year (2019)	Next Year (2020)
Up Last 7 Days	N/A	N/A	N/A	N/A



People Also Watch

Symbol	Last Price	Change	% Change
WEC WEC Energy Group, Inc.	88.29	-0.04	-0.05%
PNW Pinnacle West Capital Corporati	87.08	-0.19	-0.22%
CNP CenterPoint Energy, Inc (Holdin	24.95	+0.41	+1.69%
PEG Public Service Enterprise Group	60.29	-0.43	-0.71%
SRE Sempra Energy	147.30	+0.50	+0.34%

Recommendation Trends >



Recommendation Rating >

2.6

Up Last 30 Days	5	N/A	3	1
Down Last 7 Days	N/A	N/A	N/A	N/A
Down Last 30 Days	N/A	N/A	N/A	N/A

Growth Estimates	XEL	Industry	Sector	S&P 500
Current Qtr.	26.20%	N/A	N/A	0.02
Next Qtr.	3.30%	N/A	N/A	0.06
Current Year	6.10%	N/A	N/A	-0.03
Next Year	6.10%	N/A	N/A	0.14
Next 5 Years (per annum)	5.20%	N/A	N/A	0.07
Past 5 Years (per annum)	5.68%	N/A	N/A	N/A

1	2	3	4	5
Strong Buy	Buy	Hold	Under-perform	Sell

Analyst Price Targets (12) >

Average 65.33

Low 60.00 High 73.00

Current 61.13

Upgrades & Downgrades >

Maintains	KeyBanc: to Overweight	10/21/2019
Maintains	Mizuho: to Neutral	10/10/2019
Downgrade	Bank of America: Neutral to Underperform	9/30/2019
Maintains	UBS: to Neutral	9/6/2019
Maintains	Morgan Stanley: to Equal-Weight	9/6/2019
Maintains	Morgan Stanley: to Equal-Weight	8/16/2019

More Upgrades & Downgrades

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Alliant Energy Corporation (LNT)

(Real Time Quote from BATS)

$53.38 USD

0.00 (0.00%)

Updated Nov 22, 2019 12:41 PM ET

Add to port

Zacks Rank:
2-Buy 2

Style Scores:
D Value | D Growth | D Momentum | F VGM

Industry Rank:
Top 36% (92 out of 254)

Industry: Utility - Electric Power

Quote Overview

View All Zacks #1 Ranked Stocks

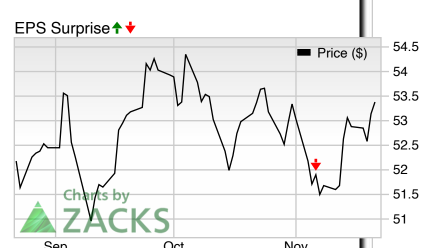
Enter Symbol

Stock Activity		Key Earnings Data	
Open	53.54	Earnings ESP	NA
Day Low	53.07	Most Accurate Est	NA
Day High	53.63	Current Qtr Est	NA
52 Wk Low	40.68	Current Yr Est	2.30
52 Wk High	54.59	Exp Earnings Date	2/20/20
Avg. Volume	1,678,496	Prior Year EPS	2.17
Market Cap	12.83 B	Exp EPS Growth (3-5yr)	5.49%
Dividend	1.42 (2.66%)	Forward PE	23.21
Beta	0.22	PEG Ratio	4.23

Utilities » Utility - Electric Power

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



Interactive Chart | Fundamental Chart

Research Reports For LNT

All Zacks' Analyst Reports »

News For LNT

- Zacks News for LNT
- Other News for LNT

Dominion (D) to Gain From $26B Investment, Dilution a Worry
11/22/19-8:59AM EST Zacks

TELUS Boosts LTE Wireless Solutions in Quebec's North Shore
11/18/19-8:11AM EST Zacks

LNT: What are Zacks experts saying now?
Zacks Private Portfolio Services

5 Utility Stocks to Buy Amid Global Economic Slowdown
11/13/19-8:14AM EST Zacks

Alliant Energy's (LNT) Q3 Earnings Improve Y/Y, Guidance Up
11/07/19-9:15AM EST Zacks

Grindrod Shipping Holdings Ltd. Announces New Financing...
10/30/19-4:05PM EST GlobeNewswire

Billion Dollar Secret

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More Zacks News for LNT

UK Dividends Calendar - Next 7 Days
11/22/19-11:06AM EST Alliance News

Foot Locker Enters Oversold Territory
11/22/19-10:32AM EST Dividend Channel

3 Real Estate Companies to Invest in Now
11/22/19-10:29AM EST InvestorPlace

My 20 Highest-Rated Dividend Stocks, No. 20 Through No. 17
11/22/19-10:20AM EST Seeking Alpha

Foot Locker Managed To Fill A Large Pair Of Shoes
11/22/19-9:39AM EST Benzinga

More Other News for LNT

Premium Research for LNT

Zacks Rank	Buy 2
Zacks Industry Rank	Top 36% (92 out of 254)
Zacks Sector Rank	Top 50% (8 out of 16)
Style Scores	D Value I D Growth I D Momentum I F VGM
Earnings ESP	NA
Research Reports for LNT	Analyst I Snapshot

(= Change in last 30 days)

View All Zacks Rank #1 Strong Buys

More Premium Research »

Premium Research: Industry Analysis

Top Peers	Symbol	Zacks Rank
Alliant Energy Corporation	**LNT**	
NRG Energy, Inc.	**NRG**	
Spark Energy, Inc.	**SPKE**	
Black Hills Corporation	**BKH**	
Eversource Energy	**ES**	
FirstEnergy Corporation	**FE**	
Fortis Inc.	**FTS**	

See all Utility - Electric Power Peers

The Zacks Rank has been called the Billion Dollar Secret. **Click here to watch the full series.** »

Company Summary

Founded in 1917, Madison, WI-based, **Alliant Energy Corporation** (LNT) is a holding company with subsidiaries engaged in regulated electric and natural gas services. The company operates primarily through four wholly owned subsidiaries – Interstate Power and Light Company (IPL), Wisconsin Power and Light Company (WPL), Resource and Corporate Services. Alliant Energy provides services to 965,000 electric and about 415,000 natural gas customers in the Midwest. On Dec 31, 2018, the company owned 42,600 miles of electric distribution lines and 9,700 miles of natural gas pipeline. The company also owns 16% of American Transmission Company, LLC (ATC), a transmission-only utility operating in the ...

Read Full Company Summary for LNT here »

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Ameren Corporation (AEE)

(Real Time Quote from BATS)

$74.96 USD

-0.23 (-0.31%)

Updated Nov 22, 2019 12:45 PM ET

Add to port Trades from $1

Zacks Rank:

3-Hold 3

Style Scores:

C Value | C Growth | C Momentum | C VGM

Industry Rank:

Top 36% (92 out of 254)

Industry: Utility - Electric Power

Quote Overview

View All Zacks #1 Ranked Stocks

Enter Symbol

Stock Activity		Key Earnings Data	
Open	75.00	Earnings ESP	0.00%
Day Low	74.27	Most Accurate Est	0.30
Day High	75.16	Current Qtr Est	0.30
52 Wk Low	62.51	Current Yr Est	3.26
52 Wk High	80.85	Exp Earnings Date	2/13/20
Avg. Volume	1,673,627	Prior Year EPS	3.37
Market Cap	18.50 B	Exp EPS Growth (3-5yr)	6.16%
Dividend	1.90 (2.53%)	Forward PE	23.06
Beta	0.19	PEG Ratio	3.74

Utilities » Utility - Electric Power

Research Reports For AEE

All Zacks' Analyst Reports »

News For AEE

- Zacks News for AEE
- Other News for AEE

Westpac "Truly Sorry" For After Regulator Money Laundering...
11/22/19-6:09AM EST Alliance News

Near-Term Outlook for Oil & Gas Pipeline Stocks Appears Dull
11/22/19-12:00AM EST Zacks

AEE: What are Zacks experts saying now?
Zacks Private Portfolio Services

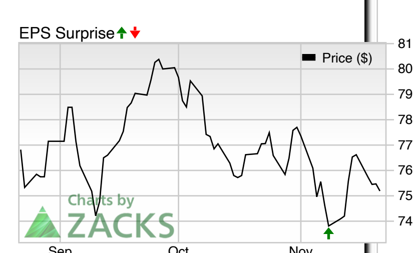
Wall Street Breakfast: Boeing Scraps For Deals At Dubai Air Show
11/20/19-5:39AM EST Seeking Alpha

Global markets fall after new tariff threat
11/20/19-3:43AM EST Seeking Alpha

GLOBAL BRIEFING: Westpac Banking Faces Massive...
11/20/19-12:37AM EST Alliance News

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



Interactive Chart | Fundamental Chart

Billion Dollar Secret

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More Zacks News for AEE

Ameren to join with Dominion for voltage optimization project
11/20/19-2:56AM EST Seeking Alpha

Ameren Illinois Announces Pricing of First Mortgage Bonds Offering due 2050
:30PM EST PR Newswire

Aura Energy Modifies Convertible Loan Pact To Secure Funding Advance
8:20AM EST Alliance News

Aura Energy Starts Cost Cutting Programme Amid Tough Conditions
11/13/19-8:06AM EST Alliance News

Ameren releases new data on environmental stewardship programs in voluntary report
EST PR Newswire

More Other News for AEE

Premium Research for AEE

Zacks Rank	**Hold** 3
Zacks Industry Rank	Top 36% (92 out of 254)
Zacks Sector Rank	Top 50% (8 out of 16)
Style Scores	**C Value I C Growth I C Momentum I C VGM**
Earnings ESP	0.00%
Research Reports for AEE	Analyst I Snapshot

(= Change in last 30 days)

View All Zacks Rank #1 Strong Buys

More Premium Research »

Premium Research: Industry Analysis

Top Peers	Symbol	Zacks Rank
Ameren Corporation	**AEE**	
NRG Energy, Inc.	**NRG**	
Spark Energy, Inc.	**SPKE**	
Alliant Energy Corporation	**LNT**	
Black Hills Corporation	**BKH**	
Eversource Energy	**ES**	
FirstEnergy Corporation	**FE**	

See all Utility - Electric Power Peers

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Billion Dollar Secret Full Ser...

The Zacks Rank has been called the Billion Dollar Secret. **Click here to watch the full series. »**

Company Summary

St. Louis, MO-based Ameren Corporation, incorporated in December 1997, is a utility company, which generates and distributes electricity and natural gas to residential, commercial, industrial and wholesale end markets in Missouri and Illinois. The company serves nearly 2.4 million electric and more than 900,000 gas customers. The company has four business segments - Ameren Missouri, Ameren Illinois Electric Distribution, Ameren Illinois Natural Gas and Ameren Transmission.

Ameren Missouri - This segment includes all the operations of Ameren Missouri. Ameren Missouri generates electricity through its coal-fired, nuclear, hydroelectric, natural gas or oil-fired and renewable facilities. Operating ...

Read Full Company Summary for AEE here »

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ACCREDITED BUSINESS BBB Rating: A+ as of 11/22/2019 Click for Profile

At the center of everything we do is a strong commitment to independent research and sharing its profitable discoveries with investors. This dedication to giving investors a trading advantage led to the creation of our proven Zacks Rank stock-rating system. Since 1988 it has more than doubled the S&P 500 with an average gain of +24.62% per year. These returns cover a period from January 1, 1988 through November 4, 2019. Zacks Rank stock-rating system returns are computed monthly based on the beginning of the month and end of the month Zacks Rank stock prices plus any dividends received during that particular month. A simple, equally-weighted average return of all Zacks Rank stocks is calculated to determine the monthly return. The monthly returns are then compounded to arrive at the annual return. Only Zacks Rank stocks included in Zacks hypothetical portfolios at the beginning of each month are included in the return calculations. Zacks Ranks stocks can, and often do, change throughout the month. Certain Zacks Rank stocks for which no month-end price was available, pricing information was not collected, or for certain other reasons have been excluded from these return calculations.

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Avista Corporation (AVA)

(Real Time Quote from BATS)

$46.44 USD

-0.21 (-0.45%)

Updated Nov 22, 2019 12:45 PM ET

Add to portfolio

Zacks Rank: 4-Sell 4

Style Scores: C Value | D Growth | A Momentum | D VGM

Industry Rank: Top 36% (92 out of 254)

Industry: Utility - Electric Power

Quote Overview

View All Zacks #1 Ranked Stocks

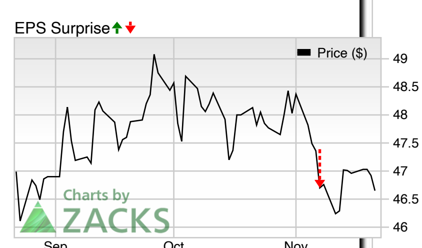
Enter Symbol

Stock Activity		Key Earnings Data	
Open	46.70	Earnings ESP	6.67%
Day Low	46.25	Most Accurate Est	0.72
Day High	46.90	Current Qtr Est	0.68
52 Wk Low	39.75	Current Yr Est	1.92
52 Wk High	52.46	Exp Earnings Date	2/19/20
Avg. Volume	294,049	Prior Year EPS	2.11
Market Cap	3.11 B	Exp EPS Growth (3-5yr)	3.32%
Dividend	1.55 (3.32%)	Forward PE	24.30
Beta	0.33	PEG Ratio	7.33

Utilities » Utility - Electric Power

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



Interactive Chart | Fundamental Chart

Research Report For AVA

All Zacks' Analyst Reports »

News For AVA

- Zacks News for AVA
- Other News for AVA

Avista (AVA) Misses Q3 Earnings and Revenue Estimates
11/07/19-7:25AM EST Zacks

Avista (AVA) Reports Next Week: What You Should Expect
10/31/19-9:34AM EST Zacks

AVA: What are Zacks experts saying now?
Zacks Private Portfolio Services

Avista (AVA) Receives PUC Approval for Oregon Rate Case
10/10/19-8:19AM EST Zacks

5 Stocks to Consider as New Analysts Initiate Coverage
10/09/19-8:09AM EST Zacks

Here's Why You Should Add CenterPoint Energy (CNP) Stock Now

Billion Dollar Secret

Access Zacks Data Feed

10/04/19-7:24AM EST Zacks

More Zacks News for AVA

7 Retail ETFs That Can`t Wait for the Holidays
11/22/19-11:03AM EST InvestorPlace

Stocks - Wall Street Rises as Trump, Xi Reheat Trade Hopes
11/22/19-9:23AM EST Investing.com

Uber Short Sellers Are Cashing Out In Droves
11/22/19-9:11AM EST Benzinga

Benzinga`s Top Upgrades, Downgrades For November 22, 2019
11/22/19-9:05AM EST Benzinga

Friday`s Vital Data: Aurora Cannabis, Twitter and Uber
11/22/19-8:25AM EST InvestorPlace

More Other News for AVA

Premium Research for AVA

Zacks Rank	Sell 4
Zacks Industry Rank	Top 36% (92 out of 254)
Zacks Sector Rank	Top 50% (8 out of 16)
Style Scores	C Value I D Growth I A Momentum I D VGM
Earnings ESP	6.67%
Research Report for AVA	Snapshot

(= Change in last 30 days)

View All Zacks Rank #1 Strong Buys

More Premium Research »

Premium Research: Industry Analysis

Top Peers	Symbol	Zacks Rank
Avista Corporation	**AVA**	
NRG Energy, Inc.	**NRG**	
Spark Energy, Inc.	**SPKE**	
Alliant Energy Corporation	**LNT**	
Black Hills Corporation	**BKH**	
Eversource Energy	**ES**	
FirstEnergy Corporation	**FE**	

See all Utility - Electric Power Peers

Recommended

Two Savings Accounts That Pay 10 Times What Your Bank Pays

The Zacks Rank has been called the Billion Dollar Secret. **Click here to watch the full series. »**

Company Summary

Avista Corporation is an energy company involved in the production, transmission and distribution of energy as well as other energy-related businesses. Avista Utilities is its operating division that provides electric service customers and natural gas customers. Its service territory covers in eastern Washington, northern Idaho and parts of southern and eastern Oregon. Alaska Energy and Resources Company is an Avista subsidiary that provides retail electric service in the city and borough of Juneau, Alaska, through its subsidiary Alaska Electric Light and Power Company.

Full Company Report for AVA »

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Black Hills Corporation (BKH)

(Real Time Quote from BATS)

$77.06 USD

+0.05 (0.07%)

Updated Nov 22, 2019 12:45 PM ET

Add to port Trades from $1

Zacks Rank:

2-Buy 2

Style Scores:

C Value | D Growth | D Momentum | D VGM

Industry Rank:

Top 36% (92 out of 254)

Industry: Utility - Electric Power

Quote Overview

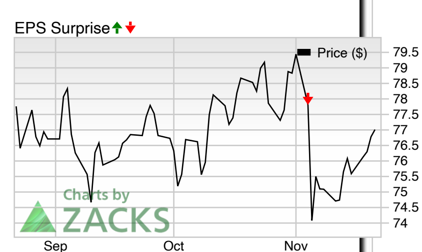
View All Zacks #1 Ranked Stocks

Enter Symbol

Stock Activity		Key Earnings Data	
Open	77.80	Earnings ESP	0.00%
Day Low	76.85	Most Accurate Est	1.09
Day High	77.80	Current Qtr Est	1.09
52 Wk Low	59.49	Current Yr Est	3.46
52 Wk High	82.01	Exp Earnings Date	2/6/20
Avg. Volume	333,986	Prior Year EPS	3.54
Market Cap	4.73 B	Exp EPS Growth (3-5yr)	4.27%
Dividend	2.14 (2.78%)	Forward PE	22.23
Beta	0.24	PEG Ratio	5.20
Utilities » Utility - Electric Power			

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



Interactive Chart | Fundamental Chart

Research Report For BKH

All Zacks' Analyst Reports »

News For BKH

- Zacks News for BKH
- Other News for BKH

TELUS Boosts LTE Wireless Solutions in Quebec's North Shore
11/18/19-8:11AM EST Zacks

5 Utility Stocks to Buy Amid Global Economic Slowdown
11/13/19-8:14AM EST Zacks

BKH: What are Zacks experts saying now?
Zacks Private Portfolio Services

Black Hills (BKH) Q3 Earnings and Revenues Miss Estimates
11/04/19-6:05PM EST Zacks

Black Hills (BKH) Earnings Expected to Grow: Should You Buy?
10/28/19-9:32AM EST Zacks

Brookfield Infrastructure Issues $500M Notes to Repay Debt

Billion Dollar Secret

Access Zacks
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10/08/19-8:09AM EST Zacks

More Zacks News for BKH

How The American Dream Can Crush Your Retirement
11/22/19-7:22AM EST Seeking Alpha

Black Hills (BKH) Presents At Mizuho Company Meetings At 54th EEI Financial Conference - Slideshow
Seeking Alpha

Dividend Champions Analysis: Add Lincoln Electric To Your Watch List
11/21/19-3:49AM EST Seeking Alpha

5 Utility Stocks To Buy Amid Global Economic Slowdown
11/13/19-10:52AM EST TalkMarkets

Ex-Dividend Reminder: Black Hills, U.S. Physical Therapy and AmerisourceBergen
Dividend Channel

More Other News for BKH

Premium Research for BKH

Zacks Rank	**Buy** 2
Zacks Industry Rank	Top 36% (92 out of 254)
Zacks Sector Rank	Top 50% (8 out of 16)
Style Scores	**C Value I D Growth I D Momentum I D VGM**
Earnings ESP	0.00%
Research Report for BKH	Snapshot

(= Change in last 30 days)

View All Zacks Rank #1 Strong Buys

More Premium Research »

Premium Research: Industry Analysis

Top Peers	Symbol	Zacks Rank
Black Hills Corporation	**BKH**	
NRG Energy, Inc.	**NRG**	
Spark Energy, Inc.	**SPKE**	
Alliant Energy Corporation	**LNT**	
Eversource Energy	**ES**	
FirstEnergy Corporation	**FE**	
Fortis Inc.	**FTS**	

See all Utility - Electric Power Peers

Recommended

Two Savings Accounts That Pay 10 Times What Your Bank Pays

The Zacks Rank has been called the Billion Dollar Secret. **Click here to watch the full series. »**

Company Summary

Black Hills Corporation is an energy company that generates wholesale electricity and produces natural gas, crude oil and coal. They serve natural gas and electric utility customers in Arkansas, Colorado, Iowa, Kansas, Montana, Nebraska, South Dakota and Wyoming.

Full Company Report for BKH »

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ACCREDITED BUSINESS BBB Rating: A+ as of 11/22/2019 Click for Profile

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CenterPoint Energy, Inc. (CNP)

(Real Time Quote from BATS)

$24.96 USD

+0.42 (1.71%)

Updated Nov 22, 2019 12:45 PM ET

Add to port

Zacks Rank:
3-Hold 3

Style Scores:
B Value | B Growth | B Momentum | B VGM

Industry Rank:
Top 36% (92 out of 254)

Industry: Utility - Electric Power

Quote Overview

View All Zacks #1 Ranked Stocks

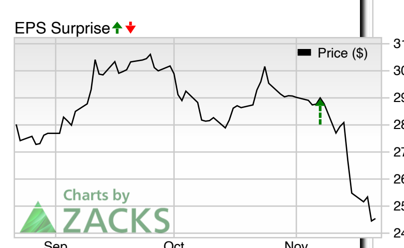
Enter Symbol

Stock Activity		Key Earnings Data	
Open	24.50	Earnings ESP	-8.38%
Day Low	24.32	Most Accurate Est	0.35
Day High	25.00	Current Qtr Est	0.38
52 Wk Low	24.25	Current Yr Est	1.66
52 Wk High	31.42	Exp Earnings Date	2/27/20
Avg. Volume	6,164,797	Prior Year EPS	1.60
Market Cap	12.32 B	Exp EPS Growth (3-5yr)	4.76%
Dividend	1.15 (4.69%)	Forward PE	14.80
Beta	0.47	PEG Ratio	3.11

Utilities » Utility - Electric Power

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



Interactive Chart | Fundamental Chart

Research Reports For CNP

All Zacks' Analyst Reports »

News For CNP

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Powerful Proof Anyone Can Invest for an Early Retirement -...
11/19/19-8:10AM EST Zacks

Signs That Your Trading Will Ruin Your Retirement - November...
11/18/19-8:17AM EST Zacks

CNP: What are Zacks experts saying now?
Zacks Private Portfolio Services

Want To Retire Early? Learn the Intelligent Investing Secret -...
11/11/19-8:09AM EST Zacks

The Extreme Risks of Trading Your Own Retirement Assets -...
11/08/19-8:09AM EST Zacks

CenterPoint Energy (CNP) Q3 Earnings Beat, Revenues Up Y/Y
11/07/19-9:29AM EST Zacks

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More Zacks News for CNP

AES Is A Definite YES
11/22/19-10:03AM EST Seeking Alpha

Healthcare On The March
11/21/19-11:10AM EST Seeking Alpha

January 2020 Options Now Available For Bed, Bath & Beyond (BBBY)
11/21/19-10:36AM EST Stock Options Channel

Interesting AMRN Put And Call Options For January 2020
11/21/19-10:36AM EST Stock Options Channel

Acasti`s Value Hidden In Plain Sight
11/21/19-10:24AM EST Seeking Alpha

More Other News for CNP

Premium Research for CNP

Zacks Rank	**Hold** 3
Zacks Industry Rank	Top 36% (92 out of 254)
Zacks Sector Rank	Top 50% (8 out of 16)
Style Scores	B **Value** I B **Growth** I B **Momentum** I B **VGM**
Earnings ESP	-8.38%
Research Reports for CNP	Analyst I Snapshot

(= Change in last 30 days)

View All Zacks Rank #1 Strong Buys

More Premium Research »

Premium Research: Industry Analysis

Top Peers	Symbol	Zacks Rank
CenterPoint Energy, Inc.	**CNP**	
NRG Energy, Inc.	**NRG**	
Spark Energy, Inc.	**SPKE**	
Alliant Energy Corporation	**LNT**	
Black Hills Corporation	**BKH**	
Eversource Energy	**ES**	
FirstEnergy Corporation	**FE**	

See all Utility - Electric Power Peers

Recommended

Two Savings Accounts That Pay 10 Times What Your Bank Pays

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Company Summary

Incorporated in 2002, Houston, TX-based CenterPoint Energy Inc. is a domestic energy delivery company that provides electric transmission & distribution, natural gas distribution and competitive natural gas sales and services operations. The company also owns a 54.1% limited partner interest in Enable Midstream Partners, a publicly traded master limited partnership it jointly controls with OGE Energy Corp.

CenterPoint Energy's reportable business segments include the following:

Electric Transmission & Distribution: CenterPoint Houston engages in electric transmission and distribution entirely within the state of ...

Read Full Company Summary for CNP here »

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Chesapeake Utilities Corporation (CPK)

(Real Time Quote from BATS)

$90.08 USD

+0.73 (0.82%)

Updated Nov 22, 2019 12:45 PM ET

Add to port | Trades from $1

Zacks Rank:
3-Hold 3

Style Scores:
C Value | **C** Growth | **B** Momentum | C VGM

Industry Rank:
Top 27% (69 out of 254)

Industry: Utility - Gas Distribution

Quote Overview

View All Zacks #1 Ranked Stocks

Enter Symbol

Stock Activity		Key Earnings Data	
Open	89.25	Earnings ESP	0.00%
Day Low	88.84	Most Accurate Est	1.14
Day High	90.23	Current Qtr Est	1.14
52 Wk Low	77.20	Current Yr Est	3.66
52 Wk High	97.00	Exp Earnings Date	2/25/20
Avg. Volume	48,634	Prior Year EPS	3.31
Market Cap	1.47 B	Exp EPS Growth (3-5yr)	7.00%
Dividend	1.62 (1.81%)	Forward PE	24.41
Beta	0.15	PEG Ratio	3.49

Utilities » Utility - Gas Distribution

Research Report For CPK

All Zacks' Analyst Reports »

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Natural Gas Market Overview: Bullish Weather And Bullish...
11/22/19-11:42AM EST Seeking Alpha

Trade Alert: Natural Gas Downside
11/22/19-10:39AM EST Seeking Alpha

CPK: What are Zacks experts saying now?
Zacks Private Portfolio Services

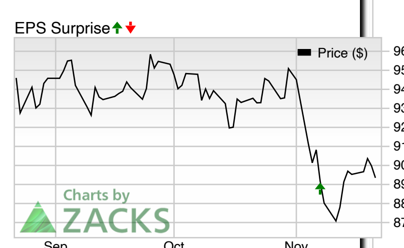
Natural Gas Prices Poised To Move Higher As Overall Weather...
11/22/19-9:45AM EST Seeking Alpha

Natural Gas - Weather Model Volatility Continues
11/21/19-12:45PM EST Seeking Alpha

Natural gas inventory draw slightly more than expected

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



Interactive Chart | Fundamental Chart

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11/21/19-9:37AM EST Seeking Alpha

More Zacks News for CPK

22 Upcoming Dividend Increases Boosted By Nike And McDonald`s
11/21/19-11:38AM EST Seeking Alpha

Prospects For Occidental Petroleum`s Permian Crude Exports Are Diminished
11/21/19-11:00AM EST Seeking Alpha

OXY January 2020 Options Begin Trading
11/21/19-9:50AM EST Stock Options Channel

DHI January 2020 Options Begin Trading
11/21/19-9:38AM EST Stock Options Channel

Single-Family Rentals: Millennials Knocking On The Door
11/21/19-8:06AM EST Seeking Alpha

More Other News for CPK

Premium Research for CPK

Zacks Rank	**Hold** 3
Zacks Industry Rank	Top 27% (69 out of 254)
Zacks Sector Rank	Top 50% (8 out of 16)
Style Scores	C **Value** I C **Growth** I B **Momentum** I C **VGM**
Earnings ESP	0.00%
Research Report for CPK	Snapshot

(= Change in last 30 days)

View All Zacks Rank #1 Strong Buys

More Premium Research »

Premium Research: Industry Analysis

Top Peers	Symbol	Zacks Rank
Chesapeake Utilities Corporation	**CPK**	
Just Energy Group, Inc.	**JE**	
Atmos Energy Corporation	**ATO**	
Clean Energy Fuels Corp.	**CLNE**	
ONE Gas, Inc.	**OGS**	
Centrica PLC	**CPYYY**	
ENN Energy Holdings Ltd.	**XNGSY**	

See all Utility - Gas Distribution Peers

The Zacks Rank has been called the Billion Dollar Secret. **Click here to watch the full series. »**

Company Summary

Chesapeake Utilities Corporation is a utility company engaged in natural gas distribution and transmission, propane distribution and marketing, advanced information services and other related businesses.Chesapeake's three natural gas distribution divisions serve residential, commercial and industrial customers in southern Delaware, Maryland's Eastern Shore and Florida. The Company's natural gas transmission subsidiary operates an interstate pipeline system that transports gas from various points in Pennsylvania to Delaware and Maryland distribution divisions.

Full Company Report for CPK »

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CMS Energy Corporation (CMS)

(Real Time Quote from BATS)

$61.68 USD

-0.27 (-0.44%)

Updated Nov 22, 2019 12:45 PM ET

Add to port | Trades from $1

Zacks Rank:
3-Hold 3

Style Scores:
D Value | C Growth | C Momentum | C VGM

Industry Rank:
Top 36% (92 out of 254)

Industry: Utility - Electric Power

Quote Overview

View All Zacks #1 Ranked Stocks

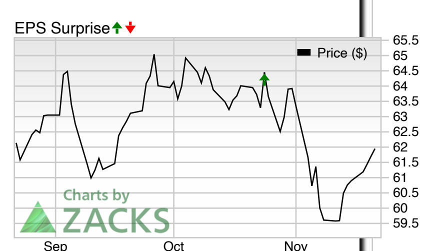
Enter Symbol

Stock Activity		Key Earnings Data	
Open	62.06	Earnings ESP	-8.97%
Day Low	61.07	Most Accurate Est	0.69
Day High	62.14	Current Qtr Est	0.75
52 Wk Low	47.63	Current Yr Est	2.49
52 Wk High	65.31	Exp Earnings Date	1/30/20
Avg. Volume	1,916,744	Prior Year EPS	2.33
Market Cap	17.58 B	Exp EPS Growth (3-5yr)	6.42%
Dividend	1.53 (2.47%)	Forward PE	24.88
Beta	0.07	PEG Ratio	3.87

Utilities » Utility - Electric Power

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



Interactive Chart | Fundamental Chart

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The Fed Slaps Down Negative Interest Rates
11/22/19-3:38AM EST Seeking Alpha

When You Can Borrow Money For Less Than Nothing
11/22/19-3:21AM EST Seeking Alpha

CMS: What are Zacks experts saying now?
Zacks Private Portfolio Services

Powell`s Testimony Challenges Both The Fed And Congress
11/21/19-7:00AM EST Seeking Alpha

Investors Would Do Well To Prepare For Greater Dispersion
11/21/19-6:03AM EST Seeking Alpha

Gold And The `Real` Interest Rate Revisited
11/20/19-1:54AM EST Seeking Alpha

Billion Dollar Secret

More Zacks News for CMS

American Outdoor Brands Corporation® Second Quarter Fiscal 2020 Financial Release and Conference Call Alert
11/21/19-4:05PM EST PR Newswire

January 2020 Options Now Available For American Outdoor Brands (AOBC)
-10:24AM EST Stock Options Channel

American Outdoor Brands Corp.:¿¿1 Becomes 2
11/18/19-11:15AM EST Seeking Alpha

Interesting CMS Put And Call Options For January 2020
11/18/19-9:40AM EST Stock Options Channel

Koninklijke Philips: Hard To Pronounce But Lets You Sleep At Night
11/15/19-8:14AM EST Seeking Alpha

More Other News for CMS

Premium Research for CMS

Zacks Rank	**Hold** 3
Zacks Industry Rank	Top 36% (92 out of 254)
Zacks Sector Rank	Top 50% (8 out of 16)
Style Scores	**D Value | C Growth | C Momentum | C VGM**
Earnings ESP	-8.97%
Research Reports for CMS	Analyst | Snapshot

(= Change in last 30 days)

View All Zacks Rank #1 Strong Buys

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Premium Research: Industry Analysis

Top Peers	Symbol	Zacks Rank
CMS Energy Corporation	**CMS**	
NRG Energy, Inc.	**NRG**	
Spark Energy, Inc.	**SPKE**	
Alliant Energy Corporation	**LNT**	
Black Hills Corporation	**BKH**	
Eversource Energy	**ES**	
FirstEnergy Corporation	**FE**	

See all Utility - Electric Power Peers

The Zacks Rank has been called the Billion Dollar Secret. **Click here to watch the full series. »**

Company Summary

Jackson, MI-based CMS Energy Corporation (CMS), founded in 1886, is the holding company of Consumers Energy Company (Consumers) and CMS Enterprises Company (Enterprises). Consumers is an electric and gas utility company that provides electricity and natural gas to residents of Michigan, and serves customers in all 68 counties of Michigan's Lower Peninsula. The Enterprises segment, through its subsidiaries and equity investments, is engaged primarily in independent power production.

CMS Energy operates principally in three business segments: Consumers electric utility, Consumers gas utility and Enterprises.

Consumers electric utility

Read Full Company Summary for CMS here

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Consolidated Edison Inc (ED)

(Real Time Quote from BATS)

$85.87 USD

-0.95 (-1.09%)

Updated Nov 22, 2019 12:45 PM ET

Add to port | Trades from $1

Zacks Rank:
3-Hold 3

Style Scores:
D Value | D Growth | D Momentum | F VGM

Industry Rank:
Top 36% (92 out of 254)

Industry: Utility - Electric Power

Quote Overview

View All Zacks #1 Ranked Stocks

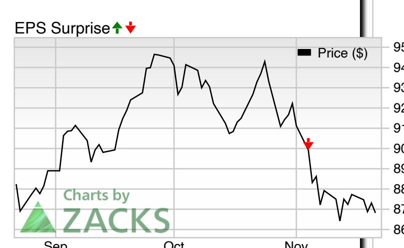
Enter Symbol

Stock Activity		Key Earnings Data	
Open	86.67	Earnings ESP	-2.15%
Day Low	85.69	Most Accurate Est	0.76
Day High	86.95	Current Qtr Est	0.78
52 Wk Low	73.30	Current Yr Est	4.33
52 Wk High	94.97	Exp Earnings Date	2/20/20
Avg. Volume	1,675,575	Prior Year EPS	4.32
Market Cap	28.86 B	Exp EPS Growth (3-5yr)	2.00%
Dividend	2.96 (3.41%)	Forward PE	20.05
Beta	0.04	PEG Ratio	10.03

Utilities » Utility - Electric Power

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



Interactive Chart | Fundamental Chart

Research Reports For ED

All Zacks' Analyst Reports »

News For ED

- Zacks News for ED
- Other News for ED

Analysts Expect VCR Will Reach $205
11/22/19-7:00AM EST ETF Channel

January 2020 Options Now Available For Ionis Pharmaceuticals...
11/21/19-10:41AM EST Stock Options Channel

ED: What are Zacks experts saying now?
Zacks Private Portfolio Services

Enviva Receives Stamp of Approval to Voluntarily Install New Air...
11/20/19-4:21PM EST Business Wire

FDA OKs Alnylam`s givosiran for AHP
11/20/19-11:36AM EST Seeking Alpha

Target can`t save all of retail
11/20/19-9:41AM EST Seeking Alpha

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11/22/19-12:42PM EST Seeking Alpha

LONDON MARKET CLOSE: Stocks Up As Trump And Xi Hint Trade...
11/22/19-11:55AM EST Alliance News

Intel (INTC) Presents At New Street Investor Conference - Slideshow
11/22/19-11:30AM EST Seeking Alpha

Nvidia and AMD Have `Momentum` in High-End Chips: Analyst
11/22/19-11:26AM EST TheStreet.com

Equatorial Guinea says pirates kidnap 7 foreigners off coast
11/22/19-11:20AM EST Associated Press, The

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Premium Research for ED

Zacks Rank	**Hold** 3
Zacks Industry Rank	Top 36% (92 out of 254)
Zacks Sector Rank	Top 50% (8 out of 16)
Style Scores	**D Value** I **D Growth** I **D Momentum** I F **VGM**
Earnings ESP	-2.15%
Research Reports for ED	Analyst I Snapshot

(= Change in last 30 days)

View All Zacks Rank #1 Strong Buys

More Premium Research »

Premium Research: Industry Analysis

Top Peers	Symbol	Zacks Rank
Consolidated Edison Inc	**ED**	
NRG Energy, Inc.	**NRG**	
Spark Energy, Inc.	**SPKE**	
Alliant Energy Corporation	**LNT**	
Black Hills Corporation	**BKH**	
Eversource Energy	**ES**	
FirstEnergy Corporation	**FE**	

See all Utility - Electric Power Peers

The Zacks Rank has been called the Billion Dollar Secret. **Click here to watch the full series. »**

Company Summary

New York-based Consolidated Edison, Inc., also known as ConEd, is a diversified utility holding company, with subsidiaries engaged in both regulated and unregulated businesses. The company was incorporated in 1823.

ConEd's regulated businesses operate through its subsidiaries – Consolidated Edison Company of New York (CECONY), Orange and Rockland Utilities (O&R), Con Edison Clean Energy Businesses, Inc. and Con Edison Transmission, Inc.

CECONY is a regulated utility that provides electricity to around 3.4 million customers and natural gas to roughly 1.1 million customers. The ...

Read Full Company Summary for ED here »

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Dominion Energy Inc. (D)

(Real Time Quote from BATS)

$83.09 USD

+0.07 (0.08%)

Updated Nov 22, 2019 12:47 PM ET

Add to port | Trades from $1

Zacks Rank:
3-Hold 3

Style Scores:
D Value | **D** Growth | **D** Momentum | D VGM

Industry Rank:
Top 36% (92 out of 254)

Industry: Utility - Electric Power

Quote Overview

View All Zacks #1 Ranked Stocks

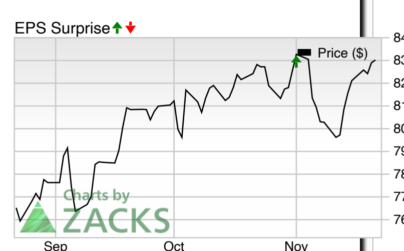
Enter Symbol

Stock Activity		Key Earnings Data	
Open	83.20	Earnings ESP	-0.46%
Day Low	82.36	Most Accurate Est	1.10
Day High	83.22	Current Qtr Est	1.10
52 Wk Low	67.41	Current Yr Est	4.17
52 Wk High	83.73	Exp Earnings Date	2/7/20
Avg. Volume	2,843,027	Prior Year EPS	4.05
Market Cap	68.33 B	Exp EPS Growth (3-5yr)	4.81%
Dividend	3.67 (4.42%)	Forward PE	19.93
Beta	0.22	PEG Ratio	4.14

Utilities » Utility - Electric Power

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



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Research Reports For D

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Dominion (D) to Gain From $26B Investment, Dilution a Worry
11/22/19-8:59AM EST Zacks

NextEra's (NEE) Unit Starts 74.9MW Project in South Carolina
11/20/19-7:28AM EST Zacks

D: What are Zacks experts saying now?
Zacks Private Portfolio Services

Should You Invest in the Fidelity MSCI Utilities Index ETF (FUTY)?
11/14/19-5:52AM EST Zacks

Utility ETFs in Focus on Mixed Q3 Earnings
11/12/19-3:29PM EST Zacks

Alliant Energy's (LNT) Q3 Earnings Improve Y/Y, Guidance Up
11/07/19-9:15AM EST Zacks

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Dominion Energy Offers Helpful Tips for Avoiding Utility Scams
11/22/19-10:30AM EST PR Newswire

Dominion Energy (D) Investor Presentation - Slideshow
11/22/19-5:17AM EST Seeking Alpha

The Top Large-Cap Sectors, Industries, And Stocks To Buy Now
11/21/19-7:00AM EST Seeking Alpha

SteelPath November MLP Update And News
11/21/19-5:36AM EST Seeking Alpha

Ameren Illinois Selects DVI For Transformative Voltage Optimization Project
11/20/19-12:45PM EST PR Newswire

More Other News for D

Premium Research for D

Zacks Rank	**Hold** 3
Zacks Industry Rank	Top 36% (92 out of 254)
Zacks Sector Rank	Top 50% (8 out of 16)
Style Scores	D **Value** I D **Growth** I D **Momentum** I D **VGM**
Earnings ESP	-0.46%
Research Reports for D	Analyst I Snapshot

(= Change in last 30 days)

View All Zacks Rank #1 Strong Buys

More Premium Research »

Premium Research: Industry Analysis

Top Peers	Symbol	Zacks Rank
Dominion Energy Inc.	**D**	
NRG Energy, Inc.	**NRG**	
Spark Energy, Inc.	**SPKE**	
Alliant Energy Corporation	**LNT**	
Black Hills Corporation	**BKH**	
Eversource Energy	**ES**	
FirstEnergy Corporation	**FE**	

See all Utility - Electric Power Peers

Recommended

Two Savings Accounts That Pay 10 Times What Your Bank Pays

The Zacks Rank has been called the Billion Dollar Secret. **Click here to watch the full series. »**

Company Summary

Richmond, VA-based Dominion Energy Inc. (earlier known as Dominion Resources Inc.) was founded in 1909. The company together with its subsidiaries produces and transports energy in the United States. It is a major energy company engaged in regulated and non-regulated electricity distribution, generation and transmission businesses. In addition, it sells electricity at wholesale prices to rural electric cooperatives, municipalities and through wholesale electricity markets.

Dominion has a portfolio of nearly 26,000 MW of generating capacity, 14,800 miles of natural gas transmission, gathering, storage and distribution pipeline, as well as 6,600 miles of electric transmission and ...

Read Full Company Summary for D here »

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- Option Chain
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DTE Energy Company (DTE)

(Real Time Quote from BATS)

$123.34 USD

-0.03 (-0.02%)

Updated Nov 22, 2019 12:47 PM ET

Add to portfolio

Zacks Rank:
3-Hold 3

Style Scores:
C Value | **D** Growth | **D** Momentum | D VGM

Industry Rank:
Top 36% (92 out of 254)

Industry: Utility - Electric Power

View All Zacks #1 Ranked Stocks

Quote Overview

Enter Symbol

Stock Activity		Key Earnings Data	
Open	123.38	Earnings ESP	-3.73%
Day Low	122.52	Most Accurate Est	1.16
Day High	124.13	Current Qtr Est	1.21
52 Wk Low	107.22	Current Yr Est	6.20
52 Wk High	134.37	Exp Earnings Date	2/6/20
Avg. Volume	1,578,319	Prior Year EPS	6.30
Market Cap	23.36 B	Exp EPS Growth (3-5yr)	6.00%
Dividend	3.78 (3.06%)	Forward PE	19.89
Beta	0.18	PEG Ratio	3.32

Utilities » Utility - Electric Power

Research Reports For DTE

All Zacks' Analyst Reports »

News For DTE

- Zacks News for DTE
- Other News for DTE

Roche Holdings Presents Positive Data From Tecentriq-Avastin Study
11/22/19-12:46PM EST Alliance News

Bulls No Longer In Charge
11/22/19-12:42PM EST Seeking Alpha

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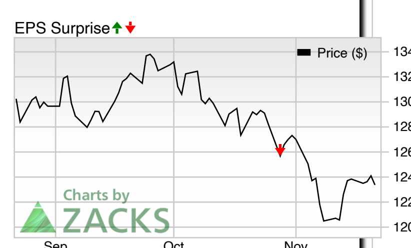
Scotch¿ Brand from 3M Partners with TaskRabbit to Support Small...
11/22/19-12:17PM EST Business Wire

FlexJobs Identifies 21 Higher-Paying Flexible Side Jobs to Consider...
11/22/19-12:00PM EST PR Web

LONDON MARKET CLOSE: Stocks Up As Trump And Xi Hint Trade...
11/22/19-11:55AM EST Alliance News

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



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T-Mobile, Comcast and Inteliquent Deliver Industry First in War...
11/21/19-9:00AM EST Business Wire

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11/21/19-7:25AM EST Seeking Alpha

DTE tells customers to 'hang up' on imposters
11/20/19-1:00PM EST PR Newswire

Four for Free? T-Mobile Has a Major iPhone ¿on Us¿ Deal for...
11/20/19-9:00AM EST Business Wire

DTE Energy's "Charging Forward" EV program quickly accelerates
11/19/19-11:46AM EST PR Newswire

More Other News for DTE

Premium Research for DTE

Zacks Rank	**Hold** 3
Zacks Industry Rank	Top 36% (92 out of 254)
Zacks Sector Rank	Top 50% (8 out of 16)
Style Scores	**C Value I D Growth I D Momentum I D VGM**
Earnings ESP	-3.73%
Research Reports for DTE	Analyst I Snapshot

(= Change in last 30 days)

View All Zacks Rank #1 Strong Buys

More Premium Research »

Premium Research: Industry Analysis

Top Peers	Symbol	Zacks Rank
DTE Energy Company	**DTE**	
NRG Energy, Inc.	**NRG**	
Spark Energy, Inc.	**SPKE**	
Alliant Energy Corporation	**LNT**	
Black Hills Corporation	**BKH**	
Eversource Energy	**ES**	
FirstEnergy Corporation	**FE**	

See all Utility - Electric Power Peers

Recommended

Two Savings Accounts That Pay 10 Times What Your Bank Pays

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Company Summary

Detroit, MI-based DTE Energy Company (DTE), incorporated in 1995, is a holding company with subsidiaries engaged in regulated and unregulated energy businesses. The company's two largest regulated subsidiaries comprise DTE Electric Company and DTE Gas Company. DTE Energy also has three non-utility segments engaged in a variety of energy-related businesses. The company's unregulated businesses include gas storage and pipelines; power and industrial projects, and energy trading operations.

Regulated Business

The Electric Utility segment consists mainly of DTE Electric Company. DTE Electric Company is a regulated electric ...

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Duke Energy Corporation (DUK)

(Real Time Quote from BATS)

$86.85 USD

+0.19 (0.22%)

Updated Nov 22, 2019 12:47 PM ET

Add to port Trades from $1

Zacks Rank:
3-Hold 3

Style Scores:
C Value | C Growth | B Momentum | C VGM

Industry Rank:
Top 36% (92 out of 254)

Industry: Utility - Electric Power

Quote Overview

View All Zacks #1 Ranked Stocks

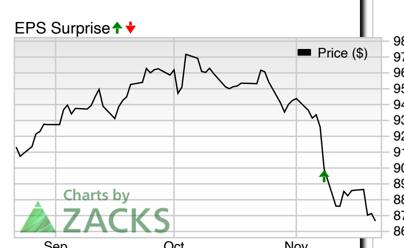
Enter Symbol

Stock Activity		Key Earnings Data	
Open	87.25	Earnings ESP	-3.59%
Day Low	86.36	Most Accurate Est	0.86
Day High	87.34	Current Qtr Est	0.89
52 Wk Low	82.46	Current Yr Est	5.01
52 Wk High	97.37	Exp Earnings Date	2/13/20
Avg. Volume	4,419,169	Prior Year EPS	4.72
Market Cap	63.18 B	Exp EPS Growth (3-5yr)	4.84%
Dividend	3.78 (4.36%)	Forward PE	17.30
Beta	0.07	PEG Ratio	3.57

Utilities » Utility - Electric Power

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



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IDACROP (IDA) to Raise Dividend Payout Range to 60-70%
11/22/19-8:53AM EST Zacks

NextEra's (NEE) Unit Starts 74.9MW Project in South Carolina
11/20/19-7:28AM EST Zacks

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MDU Resources (MDU) To Reward Shareholders With Dividend...
11/15/19-8:37AM EST Zacks

Should You Invest in the Fidelity MSCI Utilities Index ETF (FUTY)?
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Utility ETFs in Focus on Mixed Q3 Earnings
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Duke Energy contributes $500,000 to protect wetlands in Unity Park in Greenville, SC
11/22/19-11:30AM EST PR Newswire

Zuckerberg Must Embrace Governance to Sustain Facebook Stock
11/22/19-10:10AM EST InvestorPlace

Benzinga`s Top Upgrades, Downgrades For November 22, 2019
11/22/19-9:05AM EST Benzinga

Duke gets double-upgrade to Buy at Goldman with `bad news` already out
11/22/19-8:48AM EST Seeking Alpha

Gazprom to sell 3.6% stake
11/22/19-8:43AM EST Seeking Alpha

More Other News for DUK

Premium Research for DUK

Zacks Rank	**Hold** 3
Zacks Industry Rank	Top 36% (92 out of 254)
Zacks Sector Rank	Top 50% (8 out of 16)
Style Scores	C **Value** I C **Growth** I B **Momentum** I C **VGM**
Earnings ESP	-3.59%
Research Reports for DUK	Analyst I Snapshot

(= Change in last 30 days)

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Premium Research: Industry Analysis

Top Peers	Symbol	Zacks Rank
Duke Energy Corporation	**DUK**	
NRG Energy, Inc.	**NRG**	
Spark Energy, Inc.	**SPKE**	
Alliant Energy Corporation	**LNT**	
Black Hills Corporation	**BKH**	
Eversource Energy	**ES**	
FirstEnergy Corporation	**FE**	

See all Utility - Electric Power Peers

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Company Summary

Charlotte, NC-based Duke Energy Corporation, incorporated in April 1904, is a diversified energy company with a wide portfolio of domestic and international, natural gas and electric and regulated and unregulated businesses which supply, deliver and process energy in North America and selected international markets. Earlier, Duke Energy operated three business segments, namely Regulated Utilities, International Energy and Commercial Portfolio.

Currently the company primarily operates through three business segments – Electric Utilities and Infrastructure, Gas Utilities and Infrastructure, and Commercial Renewables.

Electric Utilities and Infrastructure segment ...

Read Full Company Summary for DUK here »

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Eversource Energy (ES)

(Real Time Quote from BATS)

$82.55 USD

+0.33 (0.40%)

Updated Nov 22, 2019 12:47 PM ET

Add to port Trades from $1

Zacks Rank:
2-Buy 2

Style Scores:
C Value | D Growth | F Momentum | D VGM

Industry Rank:
Top 36% (92 out of 254)

Industry: Utility - Electric Power

Quote Overview

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Day Low	81.56	Most Accurate Est	0.78
Day High	82.46	Current Qtr Est	0.80
52 Wk Low	62.61	Current Yr Est	3.46
52 Wk High	86.55	Exp Earnings Date	2/19/20
Avg. Volume	1,904,663	Prior Year EPS	3.28
Market Cap	26.62 B	Exp EPS Growth (3-5yr)	5.63%
Dividend	2.14 (2.60%)	Forward PE	23.78
Beta	0.17	PEG Ratio	4.23

Utilities » Utility - Electric Power

Research Reports For ES

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Dominion (D) to Gain From $26B Investment, Dilution a Worry
11/22/19-8:59AM EST Zacks

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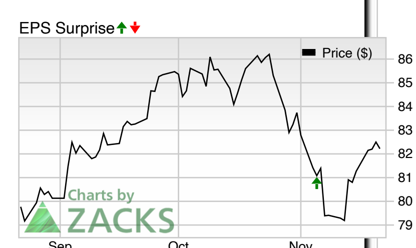
PNM Resources Boosts Assets, to Invest $3.9 B in Next 5 Years
11/22/19-7:52AM EST Zacks

Top Ranked Momentum Stocks to Buy for November 22nd
11/22/19-12:00AM EST Zacks

FirstEnergy's Focus on Modernization, Steady Outlay Bode Well
11/21/19-8:08AM EST Zacks

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



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Video: Friday Sector Laggards: Agriculture & Farm Products,...
11/22/19-11:18AM EST Market News Video

EyeGate Pharmaceuticals leads healthcare gainers; HEXO and...
11/22/19-10:03AM EST Seeking Alpha

First Week of January 2020 Options Trading For PTC Therapeutics...
11/22/19-9:37AM EST Stock Options Channel

Key events next week - healthcare
11/22/19-9:28AM EST Seeking Alpha

Arix Bioscience Porfolio Firm Harpoon Signs Deal With AbbVie
11/22/19-9:28AM EST Alliance News

More Other News for ES

Premium Research for ES

Zacks Rank	**Buy** 2
Zacks Industry Rank	Top 36% (92 out of 254)
Zacks Sector Rank	Top 50% (8 out of 16)
Style Scores	**C Value I D Growth I F Momentum I D VGM**
Earnings ESP	-2.09%
Research Reports for ES	Analyst I Snapshot

(= Change in last 30 days)

View All Zacks Rank #1 Strong Buys

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Premium Research: Industry Analysis

Top Peers	Symbol	Zacks Rank
Eversource Energy	**ES**	
NRG Energy, Inc.	**NRG**	
Spark Energy, Inc.	**SPKE**	
Alliant Energy Corporation	**LNT**	
Black Hills Corporation	**BKH**	
FirstEnergy Corporation	**FE**	
Fortis Inc.	**FTS**	

See all Utility - Electric Power Peers

The Zacks Rank has been called the Billion Dollar Secret. **Click here to watch the full series.** »

Company Summary

Eversource Energy, earlier known as Northeast Utilities, engages in the energy delivery business. The company was founded in 1927. It transmits and delivers electricity and natural gas to over 3.7 million residential, commercial and industrial customers in Connecticut, New Hampshire and Massachusetts. Eversource Energy is currently trading under the ticker symbol “ES” instead of “NU”. The company’s headquarters have remained at Hartford, CT and Boston, MA.

The reportable segments are as follows:

Electric Distribution: The segment consists of the distribution businesses of The Connecticut Light ...

Read Full Company Summary for ES here »

At the center of everything we do is a strong commitment to independent research and sharing its profitable discoveries with investors. This dedication to giving investors a trading advantage led to the creation of our proven Zacks Rank stock-rating system. Since 1988 it has more than doubled the S&P 500 with an average gain of +24.62% per year. These returns cover a period from January 1, 1988 through November 4, 2019. Zacks Rank stock-rating system returns are computed monthly based on the beginning of the month and end of the month Zacks Rank stock prices plus any dividends received during that particular month. A simple, equally-weighted average return of all Zacks Rank stocks is calculated to determine the monthly return. The monthly returns are then compounded to arrive at the annual return. Only Zacks Rank stocks included in Zacks hypothetical portfolios at the beginning of each month are included in the return calculations. Zacks Ranks stocks can, and often do, change throughout the month. Certain Zacks Rank stocks for which no month-end price was available, pricing information was not collected, or for certain other reasons have been excluded from these return calculations.

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Exelon Corporation (EXC)

(Real Time Quote from BATS)

$44.42 USD

+0.03 (0.07%)

Updated Nov 22, 2019 12:47 PM ET

Add to port

Zacks Rank:
3-Hold 3

Style Scores:
B Value | **C** Growth | **B** Momentum | **B** VGM

Industry Rank:
Top 36% (92 out of 254)

Industry: Utility - Electric Power

Quote Overview

View All Zacks #1 Ranked Stocks

Enter Symbol

Stock Activity		Key Earnings Data	
Open	44.57	Earnings ESP	-0.82%
Day Low	44.07	Most Accurate Est	0.79
Day High	44.59	Current Qtr Est	0.79
52 Wk Low	43.10	Current Yr Est	3.16
52 Wk High	51.18	Exp Earnings Date	2/14/20
Avg. Volume	7,046,322	Prior Year EPS	3.12
Market Cap	43.15 B	Exp EPS Growth (3-5yr)	4.50%
Dividend	1.45 (3.27%)	Forward PE	14.05
Beta	0.25	PEG Ratio	3.12

Utilities » Utility - Electric Power

Research Reports For EXC

All Zacks' Analyst Reports »

News For EXC

- Zacks News for EXC
- Other News for EXC

3 Top-Ranked Dividend Stocks: A Smarter Way to Boost Your...
11/21/19-8:33AM EST Zacks

SteelPath November MLP Update And News
11/21/19-5:36AM EST Seeking Alpha

EXC: What are Zacks experts saying now?
Zacks Private Portfolio Services

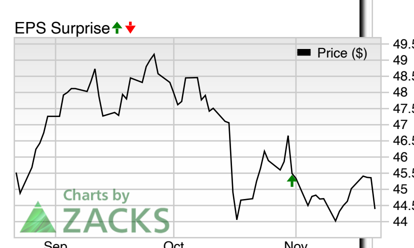
NextEra's (NEE) Unit Starts 74.9MW Project in South Carolina
11/20/19-7:28AM EST Zacks

Aveo Pharma up 4% on advancement of tivozanib
11/18/19-11:45AM EST Seeking Alpha

Merck & Co And Bayer's Vericiguat Redcues Heart Failure Risk
11/18/19-8:53AM EST Alliance News

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



Interactive Chart | Fundamental Chart

Billion Dollar Secret

Access Zacks Data Feed

More Zacks News for EXC

7 Retail ETFs That Can`t Wait for the Holidays
11/22/19-11:03AM EST InvestorPlace

Stratasys Announces 2019 Annual General Meeting of Shareholders
11/21/19-4:00PM EST Business Wire

Crude oil climbs as OPEC seen extending supply cuts until June
11/21/19-11:27AM EST Seeking Alpha

Faulty drilling indicator belies oil market that`s tighter than assumed...
11/21/19-11:00AM EST Seeking Alpha

Video: GUSH, GASL: Big ETF Inflows
11/21/19-9:46AM EST Market News Video

More Other News for EXC

Premium Research for EXC

Zacks Rank	**Hold** 3
Zacks Industry Rank	Top 36% (92 out of 254)
Zacks Sector Rank	Top 50% (8 out of 16)
Style Scores	**B Value I C Growth I B Momentum I B VGM**
Earnings ESP	-0.82%
Research Reports for EXC	Analyst I Snapshot

(= Change in last 30 days)

View All Zacks Rank #1 Strong Buys

More Premium Research »

Premium Research: Industry Analysis

Top Peers	Symbol	Zacks Rank
Exelon Corporation	**EXC**	
NRG Energy, Inc.	**NRG**	
Spark Energy, Inc.	**SPKE**	
Alliant Energy Corporation	**LNT**	
Black Hills Corporation	**BKH**	
Eversource Energy	**ES**	
FirstEnergy Corporation	**FE**	

See all Utility - Electric Power Peers

Recommended

Two Savings Accounts That Pay 10 Times What Your Bank Pays

The Zacks Rank has been called the Billion Dollar Secret. **Click here to watch the full series.** »

Company Summary

Chicago, IL-based Exelon Corporation is a utility services holding company that operates through its subsidiaries – Generation, Commonwealth Edison Company (ComEd), PECO Energy Company (PECO), Pepco Holdings (PHI) and Baltimore Gas and Electric (BGE). The company has operations in 48 states and the District of Columbia in the U.S., along with Canada. The company has a presence in every stage of the energy business: power generation, competitive energy sales, and transmission and delivery.

During second-quarter 2019, Generation, ComEd, PECO, BGE and PHI ...

Read Full Company Summary for EXC here »

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Fortis Inc. (FTS)

(Real Time Quote from BATS)

$39.75 USD

-0.15 (-0.38%)

Updated Nov 22, 2019 12:47 PM ET

Add to port | Trades from $1

Zacks Rank:
2-Buy 2
Style Scores:
C Value | D Growth | C Momentum | D VGM
Industry Rank:
Top 36% (92 out of 254)
Industry: Utility - Electric Power

Quote Overview

View All Zacks #1 Ranked Stocks

Enter Symbol

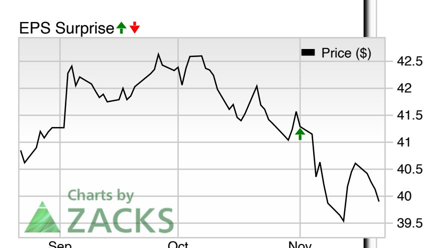
Stock Activity	
Open	39.84
Day Low	39.47
Day High	39.90
52 Wk Low	31.80
52 Wk High	42.80
Avg. Volume	399,013
Market Cap	17.49 B
Dividend	1.45 (3.64%)
Beta	0.14

Key Earnings Data	
Earnings ESP	3.23%
Most Accurate Est	0.48
Current Qtr Est	0.47
Current Yr Est	1.97
Exp Earnings Date	2/21/20
Prior Year EPS	1.91
Exp EPS Growth (3-5yr)	5.68%
Forward PE	20.25
PEG Ratio	3.56

Utilities » Utility - Electric Power

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



Interactive Chart | Fundamental Chart

Research Report For FTS

All Zacks' Analyst Reports »

News For FTS

- Zacks News for FTS
- Other News for FTS

Nordstrom Bulls Are in Control - Here`s Where the Stock Can Go...
11/22/19-10:18AM EST TheStreet.com

Nordstrom Scores Big Q3 Earnings
11/22/19-9:50AM EST Benzinga

FTS: What are Zacks experts saying now?
Zacks Private Portfolio Services

The Earnings Game Is Not Over For Gap
11/22/19-9:45AM EST Benzinga

Foot Locker Managed To Fill A Large Pair Of Shoes
11/22/19-9:39AM EST Benzinga

Top Analyst Upgrades and Downgrades: Baidu, Cerner, Duke...

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11/22/19-8:06AM EST 247WallSt

More Zacks News for FTS

ITC Holdings Corp. Receives Order from FERC on MISO base ROE Matter
11/22/19-8:50AM EST GlobeNewswire

ITC Holdings Corp. (ITC) Statement on FERC MISO Base ROE Order
11/22/19-8:40AM EST PR Newswire

Top Stock Reports for Facebook, Bank of America & Home Depot
11/21/19-12:00AM EST Zacks

Fortis Inc. Announces First Quarter Dividends - 2020
11/20/19-1:26PM EST GlobeNewswire

Financials And Real Estate Dashboard - Update
11/20/19-1:43AM EST Seeking Alpha

More Other News for FTS

Premium Research for FTS

Zacks Rank	**Buy** 2
Zacks Industry Rank	Top 36% (92 out of 254)
Zacks Sector Rank	Top 50% (8 out of 16)
Style Scores	**C Value I D Growth I C Momentum I D VGM**
Earnings ESP	3.23%
Research Report for FTS	Snapshot

(= Change in last 30 days)

View All Zacks Rank #1 Strong Buys

More Premium Research »

Premium Research: Industry Analysis

Top Peers	Symbol	Zacks Rank
Fortis Inc.	**FTS**	
NRG Energy, Inc.	**NRG**	
Spark Energy, Inc.	**SPKE**	
Alliant Energy Corporation	**LNT**	
Black Hills Corporation	**BKH**	
Eversource Energy	**ES**	
FirstEnergy Corporation	**FE**	

See all Utility - Electric Power Peers

Recommended

Two Savings Accounts That Pay 10 Times What Your Bank Pays

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Company Summary

Fortis, Inc. is engaged in electric and gas utility business. The Company offers regulated utilities comprised of electric and gas as well as engages in non-regulated hydroelectric operations. It operates primarily in Canada, United States and Caribbean. Fortis, Inc. is based in St John's, Canada.

Full Company Report for FTS »

At the center of everything we do is a strong commitment to independent research and sharing its profitable discoveries with investors. This dedication to giving investors a trading advantage led to the creation of our proven Zacks Rank stock-rating system. Since 1988 it has more than doubled the S&P 500 with an average gain of +24.62% per year. These returns cover a period from January 1, 1988 through November 4, 2019. Zacks Rank stock-rating system returns are computed monthly based on the beginning of the month and end of the month Zacks Rank stock prices plus any dividends received during that particular month. A simple, equally-weighted average return of all Zacks Rank stocks is calculated to determine the monthly return. The monthly returns are then compounded to arrive at the annual return. Only Zacks Rank stocks included in Zacks hypothetical portfolios at the beginning of each month are included in the return calculations. Zacks Ranks stocks can, and often do, change throughout the month. Certain Zacks Rank stocks for which no month-end price was available, pricing information was not collected, or for certain other reasons have been excluded from these return calculations.

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MGE Energy Inc. (MGEE)

(Real Time Quote from BATS)

$76.78 USD

+0.83 (1.09%)

Updated Nov 22, 2019 12:50 PM ET

Add to port Trades from $1

Zacks Rank:

Style Scores:
NA Value I NA Growth I NA Momentum I NA VGM
Industry Rank:
Top 36% (92 out of 254)
Industry: Utility - Electric Power

Quote Overview

View All Zacks #1 Ranked Stocks

Enter Symbol

Stock Activity		Key Earnings Data	
Open	76.29	Earnings ESP	NA
Day Low	75.49	Most Accurate Est	NA
Day High	76.84	Current Qtr Est	NA
52 Wk Low	56.64	Current Yr Est	NA
52 Wk High	80.84	Exp Earnings Date	2/28/20
Avg. Volume	86,098	Prior Year EPS	2.43
Market Cap	2.63 B	Exp EPS Growth (3-5yr)	NA
Dividend	1.41 (1.86%)	Forward PE	NA
Beta	0.32	PEG Ratio	NA

Utilities » Utility - Electric Power

News For MGEE

- Zacks News for MGEE
- Other News for MGEE

Top Ranked Momentum Stocks to Buy for October 15th
10/15/19-12:00AM EST Zacks

Bull of the Day: Skechers (SKX)
10/15/19-12:00AM EST Zacks

MGEE: What are Zacks experts saying now?
Zacks Private Portfolio Services

New Strong Buy Stocks for October 14th
10/14/19-12:00AM EST Zacks

New Strong Buy Stocks for September 19th
09/19/19-12:00AM EST Zacks

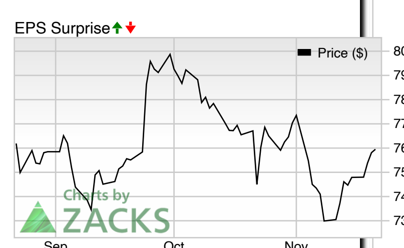
Top Ranked Growth Stocks to Buy for September 5th
09/05/19-12:00AM EST Zacks

More Zacks News for MGEE

Dividend Champions Analysis: Add Lincoln Electric To Your Watch List
11/21/19-3:49AM EST Seeking Alpha

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



Interactive Chart I Fundamental Chart

Billion Dollar Secret

MGE Energy Issues Third-Quarter Financial Update
11/08/19-3:31PM EST Business Wire

MGEE Stock Crowded With Sellers
11/08/19-10:30AM EST Energy Stock Channel

MGE: 3Q Earnings Snapshot
11/06/19-11:39AM EST Associated Press, The

MGE Energy Reports Third-Quarter Earnings
11/06/19-11:29AM EST Business Wire

More Other News for MGEE

Premium Research for MGEE

Zacks Rank	NA
Zacks Industry Rank	Top 36% (92 out of 254)
Zacks Sector Rank	Top 50% (8 out of 16)
Style Scores	**NA Value I NA Growth I NA Momentum I NA VGM**
Earnings ESP	NA
Research Report for MGEE	Snapshot

(= Change in last 30 days)

View All Zacks Rank #1 Strong Buys

More Premium Research »

Premium Research: Industry Analysis

Top Peers	Symbol	Zacks Rank
MGE Energy Inc.	**MGEE**	NA
NRG Energy, Inc.	**NRG**	
Spark Energy, Inc.	**SPKE**	
Alliant Energy Corporation	**LNT**	
Black Hills Corporation	**BKH**	
Eversource Energy	**ES**	
FirstEnergy Corporation	**FE**	

See all Utility - Electric Power Peers

The Zacks Rank has been called the Billion Dollar Secret. **Click here to watch the full series. »**

Company Summary

MGE Energy is a public utility holding company. Its principal subsidiary, MGE, generates and distributes electricity to more than 128,000 customers in Dane County, Wisconsin (250 square miles) and purchases, transports and distributes natural gas to nearly 123,000 customers in seven south-central and western Wisconsin counties (1,375 square miles). (Press Release)

Full Company Report for MGEE »

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Zacks Research is Reported On:

ACCREDITED BUSINESS BBB Rating: A+ as of 11/22/2019 Click for Profile

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NorthWestern Corporation (NWE)

(Real Time Quote from BATS)

$71.00 USD

+0.14 (0.20%)

Updated Nov 22, 2019 12:50 PM ET

Add to port

Zacks Rank: 3-Hold

Style Scores:
C Value | D Growth | C Momentum | D VGM

Industry Rank:
Top 36% (92 out of 254)

Industry: Utility - Electric Power

View All Zacks #1 Ranked Stocks

Quote Overview

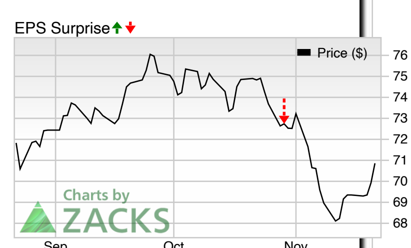
Enter Symbol

Stock Activity		Key Earnings Data	
Open	71.02	Earnings ESP	0.00%
Day Low	70.43	Most Accurate Est	1.18
Day High	71.07	Current Qtr Est	1.18
52 Wk Low	57.28	Current Yr Est	3.42
52 Wk High	76.72	Exp Earnings Date	2/10/20
Avg. Volume	284,081	Prior Year EPS	3.39
Market Cap	3.57 B	Exp EPS Growth (3-5yr)	2.73%
Dividend	2.30 (3.25%)	Forward PE	20.69
Beta	0.16	PEG Ratio	7.57

Utilities » Utility - Electric Power

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



Interactive Chart | Fundamental Chart

Research Report For NWE

All Zacks' Analyst Reports »

News For NWE

- Zacks News for NWE
- Other News for NWE

The Daily Biotech Pulse: Roche-Spark Deal Extended Again,...
11/22/19-7:24AM EST Benzinga

Stocks That Hit 52-Week Highs On Thursday
11/21/19-9:42AM EST Benzinga

NWE: What are Zacks experts saying now?
Zacks Private Portfolio Services

Dividend Champions Analysis: Add Lincoln Electric To Your...
11/21/19-3:49AM EST Seeking Alpha

PALL Weekly: Sell-Off Likely To Have Run Its Course
11/20/19-10:44AM EST Seeking Alpha

Palladium: Sentiment Remains Relatively Complacent

Billion Dollar Secret

11/20/19-3:57AM EST Seeking Alpha

More Zacks News for NWE

Nvidia and AMD Have `Momentum` in High-End Chips: Analyst
11/22/19-11:26AM EST TheStreet.com

Nvidia Stock Is Setting Up to Burst Higher
11/22/19-11:15AM EST InvestorPlace

Nordstrom Bulls Are in Control - Here`s Where the Stock Can Go Now
11/22/19-10:18AM EST TheStreet.com

Nordstrom Scores Big Q3 Earnings
11/22/19-9:50AM EST Benzinga

The Earnings Game Is Not Over For Gap
11/22/19-9:45AM EST Benzinga

More Other News for NWE

Premium Research for NWE

Zacks Rank	**Hold** 3
Zacks Industry Rank	Top 36% (92 out of 254)
Zacks Sector Rank	Top 50% (8 out of 16)
Style Scores	**C Value** I **D Growth** I **C Momentum** I **D VGM**
Earnings ESP	0.00%
Research Report for NWE	Snapshot

(= Change in last 30 days)

View All Zacks Rank #1 Strong Buys

More Premium Research »

Premium Research: Industry Analysis

Top Peers	Symbol	Zacks Rank
NorthWestern Corporation	**NWE**	
NRG Energy, Inc.	**NRG**	
Spark Energy, Inc.	**SPKE**	
Alliant Energy Corporation	**LNT**	
Black Hills Corporation	**BKH**	
Eversource Energy	**ES**	
FirstEnergy Corporation	**FE**	

See all Utility - Electric Power Peers

The Zacks Rank has been called the Billion Dollar Secret. **Click here to watch the full series. »**

Company Summary

NorthWestern Energy is a growing, financially sound, investor-owned energy company. It has provided reliable and affordable energy to customers in Montana, South Dakota and Nebraska. The company got its start in small communities, providing essential service that allowed them to grow and prosper.

Full Company Report for NWE »

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Zacks Research is Reported On:

ACCREDITED BUSINESS BBB Rating: A+ as of 11/22/2019 Click for Profile

At the center of everything we do is a strong commitment to independent research and sharing its profitable discoveries with investors. This dedication to giving investors a trading advantage led to the creation of our proven Zacks Rank stock-rating system. Since 1988 it has more than doubled the S&P 500 with an average gain of +24.62% per year. These returns cover a period from January 1, 1988 through November 4, 2019. Zacks Rank stock-rating system returns are computed monthly based on the beginning of the month and end of the month Zacks Rank stock prices plus any dividends received during that particular month. A simple, equally-weighted average return of all Zacks Rank stocks is calculated to determine the monthly return. The monthly returns are then compounded to arrive at the annual return. Only Zacks Rank stocks included in Zacks hypothetical portfolios at the beginning of each month are included in the return calculations. Zacks Ranks stocks can, and often do, change throughout the month. Certain Zacks Rank stocks for which no month-end price was available, pricing information was not collected, or for certain other reasons have been excluded from these return calculations.

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Public Service Enterprise Group Incorporated (PEG)

(Real Time Quote from BATS)

$60.32 USD

-0.40 (-0.66%)

Updated Nov 22, 2019 12:50 PM ET

Add to port

Zacks Rank:
3-Hold 3

Style Scores:
C Value | D Growth | C Momentum | D VGM

Industry Rank:
Top 36% (92 out of 254)

Industry: Utility - Electric Power

Quote Overview

View All Zacks #1 Ranked Stocks

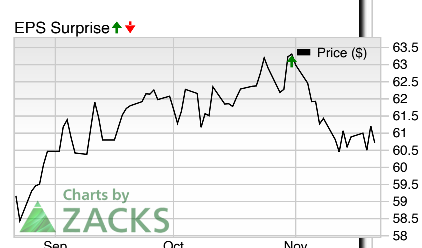
Enter Symbol

Stock Activity		Key Earnings Data	
Open	60.82	Earnings ESP	0.00%
Day Low	60.00	Most Accurate Est	0.63
Day High	60.93	Current Qtr Est	0.63
52 Wk Low	49.23	Current Yr Est	3.25
52 Wk High	63.88	Exp Earnings Date	2/26/20
Avg. Volume	1,959,041	Prior Year EPS	3.12
Market Cap	30.71 B	Exp EPS Growth (3-5yr)	3.69%
Dividend	1.88 (3.10%)	Forward PE	18.68
Beta	0.28	PEG Ratio	5.06

Utilities » Utility - Electric Power

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



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Research Reports For PEG

All Zacks' Analyst Reports »

News For PEG

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Here`s When Slack, Twilio and Other Ex Cloud Darlings Could...
11/22/19-7:02AM EST TheStreet.com

Europe`s Flash PMI Disappoints And Hong Kong Shares...
11/22/19-6:19AM EST Seeking Alpha

PEG: What are Zacks experts saying now?
Zacks Private Portfolio Services

Unity Bancorp Declares Cash Dividend
11/21/19-3:42PM EST GlobeNewswire

Galapagos And Its Partnership With Gilead: A Study
11/21/19-10:33AM EST Seeking Alpha

Arrakis Therapeutics Appoints Katrine Bosley as Chairman of the...
11/21/19-8:00AM EST Business Wire

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More Zacks News for PEG

PSEG Announces Leadership Changes For a Sustainable, Clean Energy Future
11/22/19-8:00AM EST PR Newswire

Public Service Enterprise Group (PEG) Presents At Mizuho Company Meetings At 54th EEI Financial Conference - Slideshow
11/22/19-5:41AM EST Seeking Alpha

Stocks That Hit 52-Week Highs On Thursday
11/21/19-9:42AM EST Benzinga

Benzinga`s Top Upgrades, Downgrades For November 21, 2019
11/21/19-8:45AM EST Benzinga

Guidewire Software to Announce First Quarter Fiscal 2020 Financial Results on December 5, 2019
11/21/19-8:30AM EST Business Wire

More Other News for PEG

The Zacks Rank has been called the Billion Dollar Secret. **Click here to watch the full series.** »

Premium Research for PEG

Zacks Rank	**Hold** 3
Zacks Industry Rank	Top 36% (92 out of 254)
Zacks Sector Rank	Top 50% (8 out of 16)
Style Scores	C **Value** I D **Growth** I C **Momentum** I D **VGM**
Earnings ESP	0.00%
Research Reports for PEG	Analyst I Snapshot

(= Change in last 30 days)

View All Zacks Rank #1 Strong Buys

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Company Summary

Incorporated in 1985, Newark, NJ-based Public Service Enterprise Group Inc. (PEG) or PSEG is a diversified energy company. Its operations are mostly located in the Northeastern and Mid-Atlantic parts of the United States. The company principally operates through two key subsidiaries - PSEG Power LLC (Power) and Public Service Electric and Gas Company (PSE&G).

PSEG Power is a major electricity supplier in the Northeastern and Mid-Atlantic regions. The subsidiary integrates its generating operations and gas supply obligations, including wholesale energy, fuel supply and energy trading functions, through its ...

Read Full Company Summary for PEG here »

Premium Research: Industry Analysis

Top Peers	Symbol	Zacks Rank
Public Service Enterprise Group Incorporated	**PEG**	
NRG Energy, Inc.	**NRG**	
Spark Energy, Inc.	**SPKE**	
Alliant Energy Corporation	**LNT**	
Black Hills Corporation	**BKH**	
Eversource Energy	**ES**	
FirstEnergy Corporation	**FE**	

See all Utility - Electric Power Peers

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Sempra Energy (SRE)

(Real Time Quote from BATS)

$147.40 USD

+0.60 (0.41%)

Updated Nov 22, 2019 12:50 PM ET

Add to port | Trades from $1

Zacks Rank:
3-Hold 3

Style Scores:
D Value | D Growth | B Momentum | D VGM

Industry Rank:
Top 27% (69 out of 254)

Industry: Utility - Gas Distribution

Quote Overview

View All Zacks #1 Ranked Stocks

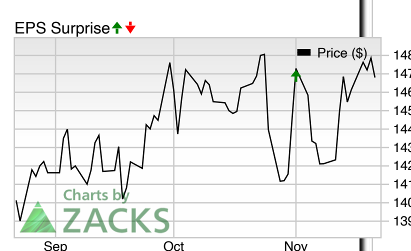
Enter Symbol

Stock Activity		Key Earnings Data	
Open	146.82	Earnings ESP	-3.90%
Day Low	146.05	Most Accurate Est	1.48
Day High	147.51	Current Qtr Est	1.54
52 Wk Low	104.88	Current Yr Est	6.13
52 Wk High	148.90	Exp Earnings Date	2/25/20
Avg. Volume	1,953,221	Prior Year EPS	5.57
Market Cap	41.38 B	Exp EPS Growth (3-5yr)	7.73%
Dividend	3.87 (2.64%)	Forward PE	23.95
Beta	0.41	PEG Ratio	3.10

Utilities » Utility - Gas Distribution

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



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Research Reports For SRE

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News For SRE

- Zacks News for SRE
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Interesting WY Put And Call Options For January 2020
11/21/19-9:52AM EST Stock Options Channel

Daily Stock Pick: Weyerhaeuser
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SRE: What are Zacks experts saying now?
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Major Red Flag: Value Transfer Between Entities
11/19/19-11:28AM EST Seeking Alpha

Stocks That Hit 52-Week Highs On Tuesday
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11/19/19-8:05AM EST Zacks

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LONDON MARKET CLOSE: Stocks Up As Trump And Xi Hint Trade Deal Is Near
11/22/19-11:55AM EST Alliance News

UK Earnings, Trading Statements Calendar - Next 7 Days
11/22/19-11:07AM EST Alliance News

February 2020 Options Now Available For Mondelez International (MDLZ)
11/22/19-9:45AM EST Stock Options Channel

Tracking Nelson Peltz`s Trian Fund Management Portfolio - Q3 2019 Update
11/22/19-9:10AM EST Seeking Alpha

Beyond Meat And The Game For The Meat-Substitute Throne
11/22/19-8:59AM EST Seeking Alpha

More Other News for SRE

Premium Research for SRE

Zacks Rank	**Hold** 3
Zacks Industry Rank	Top 27% (69 out of 254)
Zacks Sector Rank	Top 50% (8 out of 16)
Style Scores	**D Value I D Growth I B Momentum I D VGM**
Earnings ESP	-3.90%
Research Reports for SRE	Analyst I Snapshot

(= Change in last 30 days)

View All Zacks Rank #1 Strong Buys

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Premium Research: Industry Analysis

Top Peers	Symbol	Zacks Rank
Sempra Energy	**SRE**	
Just Energy Group, Inc.	**JE**	
Atmos Energy Corporation	**ATO**	
Clean Energy Fuels Corp.	**CLNE**	
ONE Gas, Inc.	**OGS**	
Centrica PLC	**CPYYY**	
Chesapeake Utilities Corporation	**CPK**	

See all Utility - Gas Distribution Peers

Recommended

Two Savings Accounts That Pay 10 Times What Your Bank Pays

The Zacks Rank has been called the Billion Dollar Secret. **Click here to watch the full series. »**

Company Summary

Sempra Energy is a southern California-based energy services holding company involved in the sale, distribution, storage and transportation of electricity and natural gas. The company has recently reorganized its subsidiaries under two operating groups: Sempra Utilities and Sempra Infrastructure. The Sempra Utilities group includes the company's utility operations: Southern California Gas Co. (SoCalGas), San Diego Gas & Electric (SDG&E) and Sempra South American Utilities. The Sempra Infrastructure group includes the company's energy infrastructure development activities, investments and operations: Sempra Mexico, Sempra LNG & Midstream and Sempra Renewable.

Read Full Company Summary for SRE here

Zacks Research is Reported On:

At the center of everything we do is a strong commitment to independent research and sharing its profitable discoveries with investors. This dedication to giving investors a trading advantage led to the creation of our proven Zacks Rank stock-rating system. Since 1988 it has more than doubled the S&P 500 with an average gain of +24.62% per year. These returns cover a period from January 1, 1988 through November 4, 2019. Zacks Rank stock-rating system returns are computed monthly based on the beginning of the month and end of the month Zacks Rank stock prices plus any dividends received during that particular month. A simple, equally-weighted average return of all Zacks Rank stocks is calculated to determine the monthly return. The monthly returns are then compounded to arrive at the annual return. Only Zacks Rank stocks included in Zacks hypothetical portfolios at the beginning of each month are included in the return calculations. Zacks Ranks stocks can, and often do, change throughout the month. Certain Zacks Rank stocks for which no month-end price was available, pricing information was not collected, or for certain other reasons have been excluded from these return calculations.

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WEC Energy Group, Inc. (WEC)

(Real Time Quote from BATS)

$88.40 USD

+0.07 (0.08%)

Updated Nov 22, 2019 12:50 PM ET

Add to port | Trades from $1

Zacks Rank:
3-Hold 3

Style Scores:
D Value | D Growth | C Momentum | D VGM

Industry Rank:
Top 36% (92 out of 254)

Industry: Utility - Electric Power

Quote Overview

View All Zacks #1 Ranked Stocks

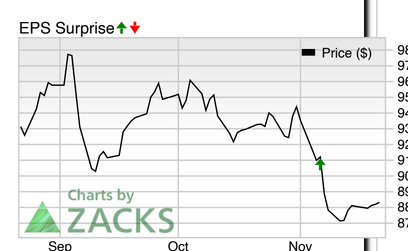
Enter Symbol

Stock Activity		Key Earnings Data	
Open	88.36	Earnings ESP	-0.68%
Day Low	87.47	Most Accurate Est	0.73
Day High	88.67	Current Qtr Est	0.74
52 Wk Low	66.75	Current Yr Est	3.53
52 Wk High	98.19	Exp Earnings Date	2/11/20
Avg. Volume	1,525,932	Prior Year EPS	3.34
Market Cap	27.86 B	Exp EPS Growth (3-5yr)	6.14%
Dividend	2.36 (2.67%)	Forward PE	25.02
Beta	-0.01	PEG Ratio	4.08

Utilities » Utility - Electric Power

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



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News For WEC

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Scotch¿ Brand from 3M Partners with TaskRabbit to Support Small...
11/22/19-12:17PM EST Business Wire

UK Shareholder Meetings Calendar - Next 7 Days
11/22/19-11:05AM EST Alliance News

WEC: What are Zacks experts saying now?
Zacks Private Portfolio Services

Chronically Corrective But Cannabis Stocks Trying To Form A...
11/22/19-8:04AM EST Seeking Alpha

Don`t Buy Tilray Stock Despite the Cannabis Rebound
11/22/19-7:25AM EST InvestorPlace

How The American Dream Can Crush Your Retirement
11/22/19-7:22AM EST Seeking Alpha

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The Daily Biotech Pulse: Roche-Spark Deal Extended Again,...
11/22/19-7:24AM EST Benzinga

WEC Energy Group (WEC) Investor Presentation - Slideshow
11/22/19-5:47AM EST Seeking Alpha

WEC Energy Group utilities named best at keeping the lights on
11/21/19-9:00AM EST PR Newswire

The Daily Biotech Pulse: Patent Win For Cellectis, Hepion Proves...
11/21/19-6:25AM EST Benzinga

First Week of NVAX July 2020 Options Trading
11/20/19-9:34AM EST Stock Options Channel

More Other News for WEC

Premium Research for WEC

Zacks Rank	**Hold** 3
Zacks Industry Rank	Top 36% (92 out of 254)
Zacks Sector Rank	Top 50% (8 out of 16)
Style Scores	**D Value I D Growth I C Momentum I D VGM**
Earnings ESP	-0.68%
Research Reports for WEC	Analyst **I** Snapshot

(= Change in last 30 days)

View All Zacks Rank #1 Strong Buys

More Premium Research »

Premium Research: Industry Analysis

Top Peers	Symbol	Zacks Rank
WEC Energy Group, Inc.	**WEC**	
NRG Energy, Inc.	**NRG**	
Spark Energy, Inc.	**SPKE**	
Alliant Energy Corporation	**LNT**	
Black Hills Corporation	**BKH**	
Eversource Energy	**ES**	
FirstEnergy Corporation	**FE**	

See all Utility - Electric Power Peers

The Zacks Rank has been called the Billion Dollar Secret. **Click here to watch the full series.** »

Company Summary

WEC Energy Group is a diversified holding company, engaged in the generation and distribution of electricity in southeastern, east central and northern Wisconsin, as well as in the upper peninsula of Michigan.

The company also distributes natural gas; owns, develops and operates coal, oil, gas and renewable fuel-based electricity generating facilities; and invests in other energy-related entities. It also develops and invests in real estate.

WEC Energy was founded in 1981 and is headquartered in Milwaukee, WI.

On Jun 29, 2015, Wisconsin Energy Corporation ...

Read Full Company Summary for WEC here »

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ACCREDITED BUSINESS
BBB Rating: A+
as of 11/22/2019
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At the center of everything we do is a strong commitment to independent research and sharing its profitable discoveries with investors. This dedication to giving investors a trading advantage led to the creation of our proven Zacks Rank stock-rating system. Since 1988 it has more than doubled the S&P 500 with an average gain of +24.62% per year. These returns cover a period from January 1, 1988 through November 4, 2019. Zacks Rank stock-rating system returns are computed monthly based on the beginning of the month and end of the month Zacks Rank stock prices plus any dividends received during that particular month. A simple, equally-weighted average return of all Zacks Rank stocks is calculated to determine the monthly return. The monthly returns are then compounded to arrive at the annual return. Only Zacks Rank stocks included in Zacks hypothetical portfolios at the beginning of each month are included in the return calculations. Zacks Ranks stocks can, and often do, change throughout the month. Certain Zacks Rank stocks for which no month-end price was available, pricing information was not collected, or for certain other reasons have been excluded from these return calculations.

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Xcel Energy Inc. (XEL)

(Real Time Quote from BATS)

$61.14 USD

-0.56 (-0.91%)

Updated Nov 22, 2019 12:50 PM ET

Add to port | Trades from $1

Zacks Rank:
3-Hold 3

Style Scores:
C Value | C Growth | D Momentum | C VGM

Industry Rank:
Top 36% (92 out of 254)

Industry: Utility - Electric Power

Quote Overview

View All Zacks #1 Ranked Stocks

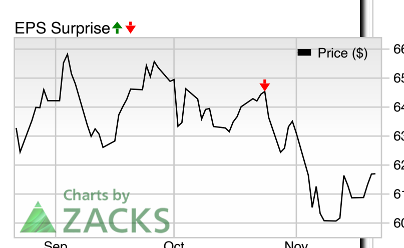
Enter Symbol

Stock Activity		Key Earnings Data	
Open	61.75	Earnings ESP	2.86%
Day Low	60.74	Most Accurate Est	0.54
Day High	61.96	Current Qtr Est	0.53
52 Wk Low	47.70	Current Yr Est	2.62
52 Wk High	66.05	Exp Earnings Date	1/30/20
Avg. Volume	3,544,960	Prior Year EPS	2.47
Market Cap	32.35 B	Exp EPS Growth (3-5yr)	5.42%
Dividend	1.62 (2.63%)	Forward PE	23.59
Beta	0.08	PEG Ratio	4.36

Utilities » Utility - Electric Power

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



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Xcel Energy's (XEL) Focus on Renewable Expansion Bodes Well
11/20/19-7:30AM EST Zacks

MDU Resources (MDU) Increases 5 Year Capex Plan by 8.6%
11/19/19-8:05AM EST Zacks

XEL: What are Zacks experts saying now?
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TREC Stock Crowded With Sellers
11/18/19-10:25AM EST Energy Stock Channel

Trecora Resources Announces Upcoming Financial Conference...
11/18/19-7:00AM EST PR Newswire

Trecora Resources (TREC) CEO Pat Quarles on Q3 2019 Results -...
11/09/19-10:49AM EST Seeking Alpha

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Xcel Energy Announces Redemption of Outstanding 4.70% Senior...
11/22/19-10:45AM EST Business Wire

Interesting XEL Put And Call Options For January 2020
11/22/19-9:38AM EST Stock Options Channel

Utilities `the most underappreciated sector,` T. Rowe Price analyst...
11/19/19-5:56AM EST Seeking Alpha

U.S. stocks mixed at close of trade; Dow Jones Industrial Average...
11/13/19-4:56AM EST Investing.com

Stocks - Disney, Apple, Nike Power Dow to New Highs
11/13/19-4:52AM EST Investing.com

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Premium Research for XEL

Zacks Rank	**Hold** 3
Zacks Industry Rank	Top 36% (92 out of 254)
Zacks Sector Rank	Top 50% (8 out of 16)
Style Scores	C **Value** I C **Growth** I D **Momentum** I C **VGM**
Earnings ESP	2.86%
Research Reports for XEL	Analyst I Snapshot

(= Change in last 30 days)

View All Zacks Rank #1 Strong Buys

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Premium Research: Industry Analysis

Top Peers	Symbol	Zacks Rank
Xcel Energy Inc.	**XEL**	
NRG Energy, Inc.	**NRG**	
Spark Energy, Inc.	**SPKE**	
Alliant Energy Corporation	**LNT**	
Black Hills Corporation	**BKH**	
Eversource Energy	**ES**	
FirstEnergy Corporation	**FE**	

See all Utility - Electric Power Peers

Recommended

Two Savings Accounts That Pay 10 Times What Your Bank Pays

The Zacks Rank has been called the Billion Dollar Secret. **Click here to watch the full series. »**

Company Summary

Minneapolis, MN-based Xcel Energy Inc. was founded in 1909 and is a holding company. Xcel with subsidiaries engaged primarily in the utility business. The company has operations in eight states – Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin.

The details of Xcel Energy's segments are mentioned below:

Electric: This segment contributed 84.2% or $9,719 million to total revenues in 2018.

Natural Gas: The segment contributed 15.1% or $1,739 million to total revenues in 2018.

Read Full Company Summary for XEL here

At the center of everything we do is a strong commitment to independent research and sharing its profitable discoveries with investors. This dedication to giving investors a trading advantage led to the creation of our proven Zacks Rank stock-rating system. Since 1988 it has more than doubled the S&P 500 with an average gain of +24.62% per year. These returns cover a period from January 1, 1988 through November 4, 2019. Zacks Rank stock-rating system returns are computed monthly based on the beginning of the month and end of the month Zacks Rank stock prices plus any dividends received during that particular month. A simple, equally-weighted average return of all Zacks Rank stocks is calculated to determine the monthly return. The monthly returns are then compounded to arrive at the annual return. Only Zacks Rank stocks included in Zacks hypothetical portfolios at the beginning of each month are included in the return calculations. Zacks Ranks stocks can, and often do, change throughout the month. Certain Zacks Rank stocks for which no month-end price was available, pricing information was not collected, or for certain other reasons have been excluded from these return calculations.

Wed, Oct 16, 2019

Duff & Phelps' U.S. Normalized Risk–Free Rate Decreased from 3.5% to 3.0% Effective September 30, 2019

 Roger J. Grabowski  James Harrington

Executive Summary

The Equity Risk Premium (ERP) changes over time. Fluctuations in global economic and financial conditions warrant periodic reassessments of the selected ERP and accompanying risk-free rate.

Based on current market conditions, Duff & Phelps is reaffirming its U.S. Equity Risk Premium recommendation of 5.5% to be used in conjunction with a normalized risk-free rate.

However, based on declining real interest rates and long-term growth estimates for the U.S. economy, we are lowering the U.S. normalized risk-free rate from 3.5% to 3.0% when developing discount rates as of September 30, 2019 and thereafter, until further guidance is issued. In summary:

Equity Risk Premium: Reaffirmed at 5.5%

Risk-Free Rate: Decreased from 3.5% to 3.0% (normalized)

Base U.S. Cost of Equity Capital: 8.5% (5.5% + 3.0%)

We will be issuing a more complete Client Alert covering our analysis of the Risk-Free Rate and Equity Risk Premium in mid-October 2019.

Background

The Equity Risk Premium (ERP) is a key input used to calculate the cost of capital within the context of the Capital Asset Pricing Model (CAPM) and other models. Duff & Phelps regularly reviews fluctuations in economic and financial market conditions that warrant a periodic reassessment of the ERP.[1]

Based on current market conditions, we are reaffirming the recommended U.S. ERP of 5.5%, which was effective for valuations dates as of December 31, 2018 and thereafter. We will maintain our recommendation to use a 5.5% U.S. ERP when developing discount rates until there is evidence indicating equity risk in financial markets has materially changed. We are closely monitoring economic conditions.

The current ERP recommendation (5.5%) was developed in conjunction with a “normalized” 20-year yield on U.S. government bonds as a proxy for the risk-free rate (Rf). Based on recent academic literature and market evidence of a secular decrease in real interest rates (a.k.a. the “rental” rate) and lower long-term real GDP growth estimates for the U.S. economy, we are lowering our recommended normalized risk-free rate from 3.5% to 3.0% for valuation dates as of September 30, 2019 and thereafter.

Methods of Estimating a Normalized Risk-free Rate

Estimating a normalized risk-free rate can be accomplished in a number of ways, including (i) simple averaging, and (ii) various “build-up” methods.[2]

The first method of estimating a normalized risk-free rate entails calculating averages of yields to maturity on long-term government securities over various periods. This method’s implied assumption is that government bond yields revert to the mean. For example, as of September 20, 2019, the 10-year moving-average for the yield on 20-year U.S. Treasury bonds was 3.0%. In contrast, the corresponding spot yield on September 20, 2019 was 2.0%.

Taking the moving-average over the last 10 years is a simple way of “normalizing” the risk-free rate. An issue with using historical averages, though, is selecting an appropriate comparison period that can be used as a reasonable proxy for the future.

The second method of estimating a normalized risk-free rate entails using a simple build-up method, where the components of the risk-free rate are estimated and then added together. Conceptually, the risk-free rate can be (loosely) illustrated as the sum of the following two components:[3]

Risk-Free Rate = Real Rate + Expected Inflation

In Exhibit 1, we summarize long-term real rate estimates and inflation expectations for the United States through mid-September 2019, based on data assembled from a variety of sources. We also display the spot 20-year U.S. Treasury yield and its long-term (10-year) trailing average as of September 20, 2019.

Exhibit 1: Long–Term Spot and Normalized Risk–Free Rates for the United States September 2019 (approximately):[4, 5, 6]

Estimated Long-term Real Risk-Free Rate	0.0% to 2.0%
Expected Long-term Inflation	1.6% to 2.6%
Range of Normalized Risk-free Rates	**1.6% to 4.6%**
Midpoint	3.1%
20-Year U.S. Government Securities:	
- Spot Rate	2.0%
- Long-Term (10-year) Trailing Average Yield	3.0%
Concluded Normalized Risk-free Rate	**3.0%**

Academic research in the area of real rates has been very active recently. We rely on estimates from these different academic studies to infer our estimated long-term real risk-free rate range of 0.0% - 2.0%. Academic researchers and economic analysts have proposed a number of explanations for the secular (i.e., not cyclical or temporary) decline in global real interest rates, which they argue precedes the onset of the 2008 global financial crisis. The following are some of the most-often-cited factors:[7]

Lower global long-run output and productivity growth

Shifting demographics (aging population leading to slower labor force expansion)

Global "savings glut"

Safe asset shortage (increased demand for safe-haven assets, accompanied by a declining supply)

With regards to long-term inflation expectations, the same declining trend has been taking hold in the United States and across several other developed markets over the last few years. Inflation has been persistently below the 2.0% target set by major central banks, such as the Federal Reserve Bank (Fed), the European Central Bank, the Bank of England, and the Bank of Japan.

Can the Normalized Risk-free Rate Decline While the Spot Yield is Increasing?

A long-term "normalized" risk-free rate attempts to capture the sustainable average return of long-term bonds issued by a government considered "safe" or free of default risk (e.g., U.S. Treasuries).[8,9] However, the use of a normalized risk-free rate during certain periods does not assume that "spot" rates will not fluctuate during these periods. Spot rates will almost undoubtedly fluctuate during the current period as well, just as they have fluctuated in all previous periods of normalization. This fluctuation in itself does not alter our recommendation based on economic fundamentals.

Duff & Phelps will continue to monitor risk-free rates and other cost of capital inputs very closely. If and when (i) long-term spot yields increase to a level that approaches the Duff & Phelps recommended U.S. normalized risk-free rate (e.g. differences are lower than 50 b.p.), and (ii) there is evidence that this increase in spot yields is not transitory, we will then consider recommending a return to using the spot rate as the basis for the risk-free rate.

Duff & Phelps' U.S. Equity Risk Premium Recommendation and "Base" Cost of Equity

Duff & Phelps last changed its U.S. ERP recommendation on December 31, 2018. On that date, our ERP recommendation was increased to 5.5% (from 5.0%) in response to evidence that suggested a heightened level of risk in financial markets.

Duff & Phelps monitors various economic and financial market indicators, as well as two quantitative models as corroboration to arrive at its U.S. ERP recommendation. While current evidence seems to be pointing to a decline in equity risk in financial markets relative to December 31, 2018, from a qualitative perspective we deem it prudent to adopt a "wait and see" approach, especially with mounting indications of deteriorating global economic growth prospects and a rise in global trade uncertainty.

Accordingly, Duff & Phelps is reaffirming the recommended U.S. ERP of 5.5%, to be used in conjunction with a normalized risk-free rate of 3.0%, when developing discount rates as of September 30, 2019 and thereafter. The combination of the new normalized risk-free rate (3.0%) and the reaffirmed U.S. recommended ERP (5.5%) result in an implied U.S. "base" cost of equity capital estimate of 8.5% (3.0% + 5.5%). Were we to use the spot yield-to-maturity on 20-year U.S. Treasuries of 2.0% as of September 20, 2019, one would have to increase the ERP assumption accordingly. One can determine the ERP against the spot 20-year yield as of September 20, 2019, inferred by Duff & Phelps' recommended U.S. ERP (used in conjunction with the normalized risk-free rate), by using the following formula:

U.S. ERP Against Spot 20-Year Yield (Inferred) = D&P Recommended U.S. ERP
+ Normalized Risk-Free Rate
– Spot 20-Year U.S. Treasury Yield
= 5.5% + 3.0% – 2.0% = 6.5%

Sources

[1] For a discussion of some of the studies and factors we evaluate, refer to Chapter 3 of the Duff & Phelps Cost of Capital Navigator "Resources" Section or to Duff & Phelps' Client Alert entitled "Duff & Phelps Increased U.S. Equity Risk Premium Recommendation to 5.5%, Effective December 31, 2018". To obtain a free copy of this Client Alert, visit www.duffandphelps.com/costofcapital.

[2] For a more detailed discussion on reasons for normalization and methods that can be used to normalize risk-free rates, refer to Chapter 3 in the Duff & Phelps Cost of Capital Navigator "Resources" section.

[3] This is a simplified version of the "Fisher equation", named after Irving Fisher. Fisher's "The Theory of Interest" was first published by Macmillan (New York), in 1930.

[4] Pescatori, Andrea, and Mr Jarkko Turunen. Lower for longer: neutral rates in the United States. No. 15-135. International Monetary Fund, 2015.; Kiley, Michael T., "What Can the Data Tell Us About the Equilibrium Real Interest Rate?", Finance and Economics Discussion Series 2015–077. Washington: Board of Governors of the Federal Reserve System (August 2015); Lubik, Thomas A. and Christian Matthes "Calculating the Natural Rate of Interest: A Comparison of Two Alternative Approaches", Richmond Fed Economic Brief (October 2015); Johannsen, Benjamin K. and Elmar Mertens (2016), "The Expected Real Interest Rate in the Long Run: Time Series Evidence with the Effective Lower Bound", FEDS Notes, Washington: Board of Governors of the Federal Reserve System, February 9, 2016; Laubach, Thomas, and John C. Williams. "Measuring the natural rate of interest redux." Business Economics 51, no. 2 (2016): 57-67; Taylor, John B., and Volker Wieland. "Finding the equilibrium real interest rate in a fog of policy deviations." Business Economics 51, no. 3 (2016): 147-154.; Lansing, Kevin J., "Projecting the Long-Run Natural Rate of Interest", FRBSF Economic Letter 2016–25 (August 2016); Hamilton, James, Ethan Harris, Jan Hatzius, and Kenneth West, "The Equilibrium Real Funds Rate: Past, Present and Future", IMF Economic Review, November 2016, Vol. 64, Issue 4, p. 660–707; Holston, Holston, Kathryn, Thomas Laubach, and John C. Williams. "Measuring the natural rate of interest: International trends and determinants." Journal of International Economics 108 (2017): S59-S75; Del Negro, Marco and Giannone, Domenico and Giannoni, Marc P. and Tambalotti, Andrea (2017-05-11), "Safety, Liquidity, and the Natural Rate of Interest", FRB of NY Staff Report No. 812; Sichel, Daniel E. & Wang, J. Christina (2017), "The equilibrium real policy rate through the lens of standard growth models", Current Policy Perspectives 17-6, Federal Reserve Bank of Boston;

Lunsford, Kurt G., and Kenneth D. West. “Some evidence on secular drivers of US safe real rates” No. w25288. National Bureau of Economic Research, 2018.; Wieland, V. (2018). Chapter 2 The Natural Rate - Section One - R- Star: The Natural Rate and Its Role in Monetary Policy; In the Structural Foundations of Monetary Policy (pp. 45-61). Hoover Institution Press, Stanford University; Viktors Ajevskis, (2018). "The Natural Rate of Interest: Information Derived from a Shadow Rate Model," Working Papers 2018/02, Latvijas Banka; Fiorentini, Gabriele, Galesi, Alessandro, Perez-Quirós, Gabriel and Sentana, Enrique, (2018), "The rise and fall of the natural interest rate," No 1822, Working Papers, Banco de España; Christensen, Jens HE, and Glenn D. Rudebusch. "A new normal for interest rates? Evidence from inflation-indexed debt." Review of Economics and Statistics (2017): 1- 46; Lewis, Kurt F., and Francisco Vazquez-Grande (2017). “Measuring the Natural Rate of Interest: Alternative Specifications," Finance and Economics Discussion Series 2017-059. Washington: Board of Governors of the Federal Reserve System; R.C.M. Beyer, V. Wieland/Journal of International Money and Finance 94 (2019) 1–14

5. We continue to also rely on the results of Haubrich et al (2012), Lubick and Matthes (2015), Laubach and Williams (2016), and Holston et al. (2017) work, which are updated on a regular basis and published in the Federal Reserve Bank of Cleveland’s website, the Federal Reserve Bank of Richmond website, and the Federal Reserve Bank of New York’s website, respectively.

6. “The Livingston Survey: June 2019,” Federal Reserve Bank of Philadelphia (June 7, 2019); “Survey of Professional Forecasters: Third Quarter 2019,” Federal Reserve Bank of Philadelphia (August 2019); Blue Chip Financial Forecasts (June 1, 2019 and September 1, 2019); Blue Chip Economic Indicators (March 2019 and August 2019); “Consensus Forecasts – A Digest of International Economic Forecasts”, Consensus Economics Inc. (April 2019 and August 2019); Federal Reserve Bank of Cleveland (estimates as of August 2019); Philadelphia Federal Reserve, Aruoba Term Structure of Inflation Expectations (estimates as of August 2019); the University of Michigan Inflation Expectations, September 2019.

7. For a more detailed discussion of some of these and other factors, see, for example, Rachel, Lukasz and Thomas D Smith “Secular drivers of the global real interest rate”, Bank of England Staff Working Paper No. 571, December 2015. Also, consider reviewing Chapter 3 in the Duff & Phelps Cost of Capital Navigator “Resources” section

8. Beginning with the financial crisis of 2008 (the “Financial Crisis”), analysts have had to reexamine whether the “spot” rate is still a reliable building block upon which to base their cost of equity capital estimates. The Financial Crisis challenged long-accepted practices and highlighted potential problems of simply continuing to use the spot yield-to-maturity on a safe government security as the risk-free rate, together with historical equity risk premiums, without any further adjustments.

9. The general framework for the normalization argument could be described as follows: (i) the extremely-low rates we have experienced in recent years would not exist without the market intervention by “non-market” participants (i.e., central banks) pushing rates down “artificially”, (ii) these abnormally-low rates are not sustainable in the long-term, and (iii) rates tend to revert to a mean that reflects the long-term relationship between nominal and real interest rates.

November 8, 2019

THIRD QUARTER 2019

Duke Energy Earnings Review & Business Update

Lynn Good — *Chairman, President & CEO*

Steve Young — *Executive Vice President & CFO*

DUKE ENERGY®

BUILDING A **SMARTER** ENERGY FUTURE®

Safe Harbor statement

This presentation includes forward-looking statements within the meaning of the federal securities laws. Actual results could differ materially from such forward-looking statements. The factors that could cause actual results to differ are discussed in the Appendix herein and in Duke Energy's SEC filings, available at www.sec.gov.

Regulation G disclosure

In addition, today's discussion includes certain non-GAAP financial measures as defined under SEC Regulation G. A reconciliation of those measures to the most directly comparable GAAP measures is available in the Appendix herein and on our Investor Relations website at www.duke-energy.com/investors/.

Topics for today's call

BUSINESS UPDATE

Lynn Good, Chairman, President & CEO

- Third quarter 2019 update
- Progress on strategic initiatives
- Legislative updates

FINANCIAL UPDATE

Steve Young, Executive VP & CFO

- Third quarter 2019 earnings drivers
- Economic conditions and volume trends
- Regulatory updates
- Financing plan update
- Key investor considerations

Third quarter 2019 update

$1.82

REPORTED DILUTED EPS FOR 3Q 2019 COMPARED TO $1.51 IN 3Q 2018

$1.79

ADJUSTED DILUTED EPS FOR 3Q 2019 COMPARED TO $1.65 IN 3Q 2018

$4.95 - $5.15

NARROWING 2019 EPS GUIDANCE RANGE (1)

FINANCIAL HIGHLIGHTS(1)

- Raising the midpoint of 2019 EPS guidance range on strong year-to-date results
- EPS growth of 7% through the first three quarters
- Reaffirming 4-6% long-term growth CAGR through 2023(2)

OPERATIONAL HIGHLIGHTS

- Well executed response to Hurricane Dorian with 95% of outages restored within 24 hours
- System performed well during recent sustained heat wave through summer and early fall
- Duke Energy named to Dow Jones Sustainability Index for 14th consecutive year
- Winner of U.S. Transparency Award by Labrador Group for utilities

(1) Based on adjusted diluted EPS
(2) Off the midpoint of the original 2019 guidance range, or $5.00

Working to achieve net-zero carbon emissions by 2050

Companywide CO_2 Emissions Reduction Goals(1)

- ❑ Cut CO_2 emissions by at least 50% by 2030
- ❑ Attain net-zero CO_2 emissions by 2050

CO_2 Reductions Already Achieved(2)

- ✓ Exceeded 2025 reduction benchmarks agreed to by the U.S. for the Paris climate accord
- ✓ Met the 2030 CO_2 emission-reduction requirements of EPA's former Clean Power Plan almost 11 years early

PATH TO A LOW-CARBON FUTURE

- Collaborate and align with our states and stakeholders as we transform
- Accelerate transition to cleaner energy solutions
- Modernize our electric grid
- Continue to operate existing carbon-free technologies, including nuclear and renewables
- Advocate for sound public policy that advances technology and innovation

(1) From 2005 levels
(2) Achieved 31% reduction as of 2018, including a 35% reduction in the Carolinas

Generating cleaner energy

ELECTRIC UTILITIES AND INFRASTRUCTURE

- Asheville combined cycle (DEP) on target for late-2019 completion (part of the $1.1B Western Carolinas Modernization Project)
- Second renewable energy RFP in NC launched in October; expect ~1,200 MW to be procured through two RFPs
- Advancing 700 MW of solar projects in FL by 2022

COMMERCIAL RENEWABLES

- Approximately 380 MW[1] of wind and solar projects announced in Q3, bringing YTD total to over 1,500 MWs
- Line-of-sight to substantially all of our growth prospects for 2019 & 2020; and ~70% of the five-year plan

TARGETING ≥50% REDUCTION[2] IN CO_2 EMISSIONS BY 2030 AND NET-ZERO BY 2050

(1) See appendix for detailed project listing
(2) From 2005 levels

Expanding natural gas infrastructure

ATLANTIC COAST PIPELINE

- SCOTUS agreed to hear appeal of the Appalachian Trail decision; DOJ and Solicitor General joined the appeal; expect decision in Q2 2020
- Work continues with Fish and Wildlife Service to resolve issues with Biological Opinion and Incidental Take Statement identified by the Fourth Circuit
  - Expect reissued permits in the first half of 2020
- Expect mechanical completion of the project in late 2021 with full in-service in the first half of 2022
  - No longer pursuing phased in-service schedule
- Estimated cost $7.3 to $7.8 billion(1)
- Remain confident in the project and committed to its completion

COMMITTED TO BRINGING LOW-COST NATURAL GAS TO UNDERSERVED SOUTHEAST

(1) Represents total project cost, of which Duke Energy's share is 47%. Excludes AFUDC

Legislative updates

North Carolina

- SB559 was enacted into law on Nov. 6, enabling storm cost securitization
- Provides customers with 15-20% savings on storm recovery costs
- Supports balance sheet strength
- Opportunity for progress on alternative regulatory mechanisms, including multi-year rate plans and ROE bands, in the 2020 stakeholder process related to the Governor's Clean Energy Plan
- Near-term focus remains on rate case execution

Ohio

- HB247 would further grid modernization, technology deployment and distributed generation
- Bill passage could provide a pathway for Ohio to be a national leader in energy infrastructure and innovation

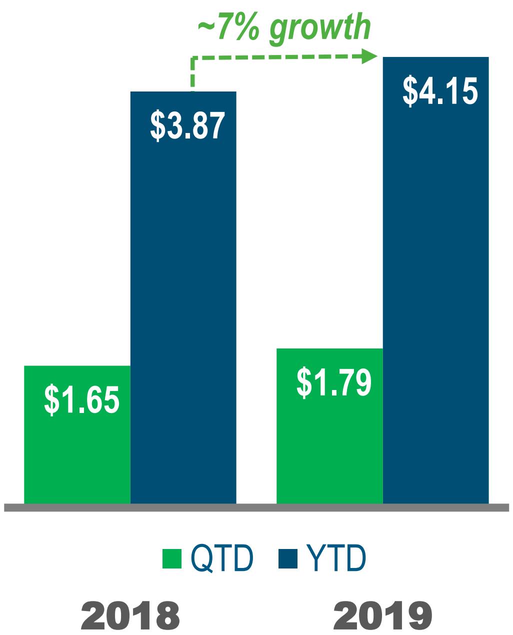
Florida

- SB796, passed in June 2019, authorizes investments to further resiliency of the grid against extreme weather events
- FPSC is in the process of adopting a final rule; each Florida utility to submit Storm Protection Plans in 2020

CONTINUE TO ADVOCATE FOR SOLUTIONS THAT BENEFIT CUSTOMERS

3Q 2019 adjusted diluted EPS summary and primary drivers

ADJUSTED DILUTED EARNINGS PER SHARE



$4.95 - $5.15

NARROWING 2019 EPS GUIDANCE RANGE(3)

SEGMENT RESULTS VS. PRIOR YEAR QUARTER(1)

Electric Utilities & Infrastructure, +$191 M (+$0.25 per share(2))

- ▲ Contribution from base rate changes and riders (+$0.11 per share)
- ▲ Weather (+$0.09 per share)
- ▲ Lower storm costs, effective management and timing of O&M expenses (+$0.07 per share)
- ▼ Higher depreciation and amortization, primarily due to a growing asset base (-$0.03 per share)
- ▼ Lower volumes, primarily industrial (-$0.03 per share)

Gas Utilities & Infrastructure, +$8 M (+$0.01 per share)

- ▲ Higher earnings from midstream investments

Commercial Renewables, +$14 M (+$0.02 per share)

- ▲ Favorable wind resource and new growth projects

Other, -$84 M (-$0.11 per share)

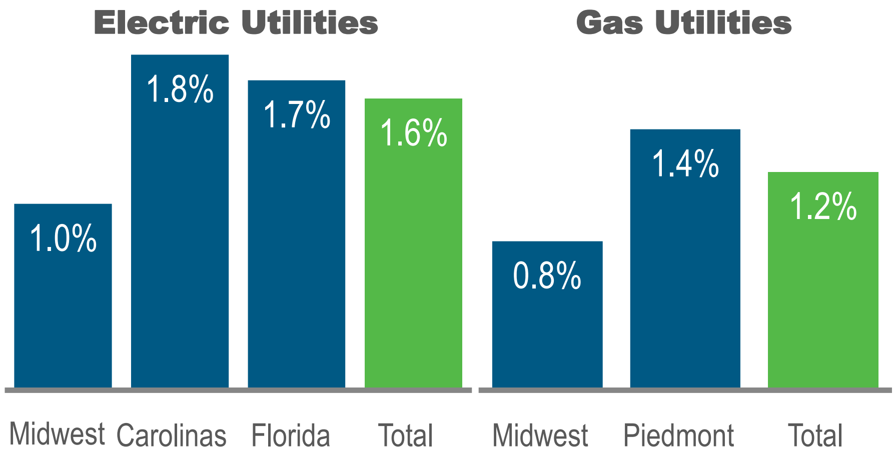
- ▼ Higher financing costs and timing of income tax expense

Share Dilution (-$0.03 per share)

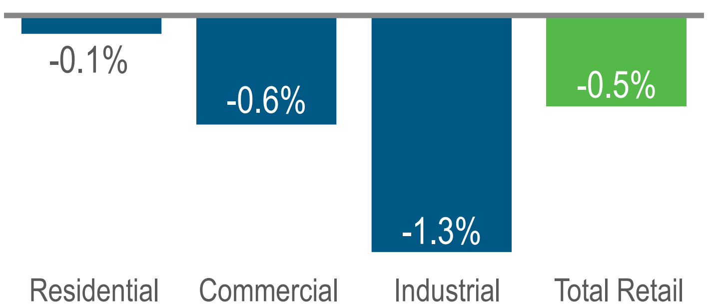
(1) Detailed drivers of adjusted segment income (loss) are available in the 3Q 2019 earnings release located on our Investor Relations website at www.duke-energy.com/investors/
(2) Excludes share dilution of -$0.03
(3) Based on adjusted diluted EPS

Customer growth and weather-normal electric volume trends

ANNUAL GROWTH IN NUMBER OF RESIDENTIAL CUSTOMERS



ROLLING 12-MONTH RETAIL ELECTRIC VOLUME GROWTH



RESIDENTIAL

- Increase in average number of customers in our attractive service territories drives long-term volume growth for electric and gas utilities
- Company-sponsored energy efficiency programs contributed to lower usage per customer

COMMERCIAL

- Weakness in big box retail stores resulting from store closures and energy efficiency penetration
- Data center expansion continues to be a positive

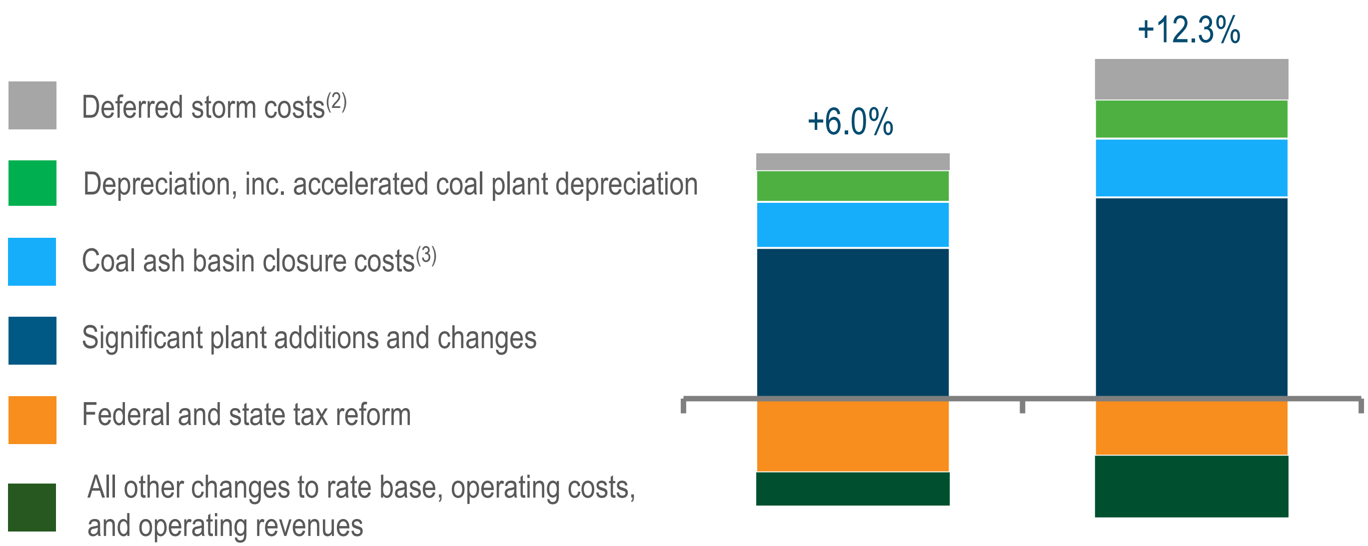
INDUSTRIAL

- Manufacturing contractions contributed to weak volumes in the quarter
- Expect improvement as customers recover from production declines and temporary outages

EXPECTING FLAT WEATHER-NORMAL RETAIL SALES GROWTH FOR 2019

Rate cases in the Carolinas support clean energy future

	Duke Energy Carolinas	Duke Energy Progress
Retail revenue increase requested	$291 M	$464 M
Return on equity requested	10.3%	
Equity component of capital structure	53%	
Proposed rate base(1)	~$15.5 B	~$10.8 B
Rates requested to be in effect, if approved	Aug. 1, 2020	Sept. 1, 2020



DUKE ENERGY CAROLINAS
FILED CASE
SEPT. 30, 2019
HEARINGS SCHEDULED
MARCH 2020

DUKE ENERGY PROGRESS
FILED CASE
OCT. 30, 2019
HEARINGS EXPECTED
EARLY 2020

(1) As of June 30, 2019 and adjusted for known and measurable changes through Jan. 2020 (DEC) and Feb. 2020 (DEP)
(2) With passage of SB559 (legislation for storm securitization) DEC and DEP will seek to securitize these costs
(3) Coal ash basin closure costs include recovery of costs incurred Jan. 2018 – Jan. 2020 (DEC) and Sep. 2017 – Feb. 2020 (DEP), over a five year period

Financing plan update

ADDITIONAL EQUITY TO MAINTAIN BALANCE SHEET STRENGTH…

- Expect to issue ~$2.5 billion of equity to maintain our strong credit metrics during ACP construction
  - Enables company to address a wider range of ACP outcomes
  - Expect to issue by end of 2020 to coincide with timing of ACP spend; will be opportunistic to efficiently source equity
  - Minimal dilution to 2020 earnings
  - Dilution in 2021 and 2022 mitigated by incremental ACP earnings
- Expect common stock issuances of $500 million per year through 2022 via DRIP/ATM programs to support $37 billion growth capital plan
- Creates balance sheet flexibility to pursue accretive capital investment opportunities or moderate DRIP/ATM programs after 2022

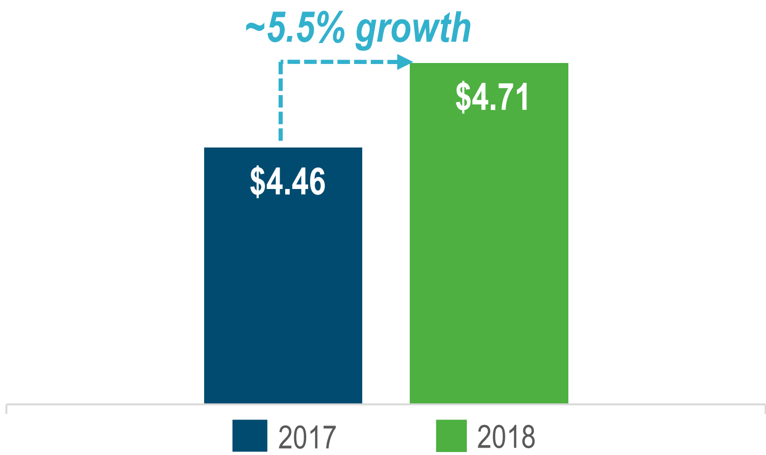
…WITH ADDITIONAL SUPPORT FOR CASH FLOW AND CREDIT PROFILE

- Commercial Renewables minority stake sale to John Hancock closed Sept. 2019
  - $415 million pre-tax proceeds used to offset debt
- Expect $1.1 billion refundable AMT credits in 2019-2022
  - ~$575 million received in Oct. 2019 and $275 million expected in 2020
- Preferred stock issuances of $2 billion in 2019 at historically low rates

COMMITTED TO MAINTAINING STRONG CREDIT QUALITY & INVESTMENT-GRADE RATINGS

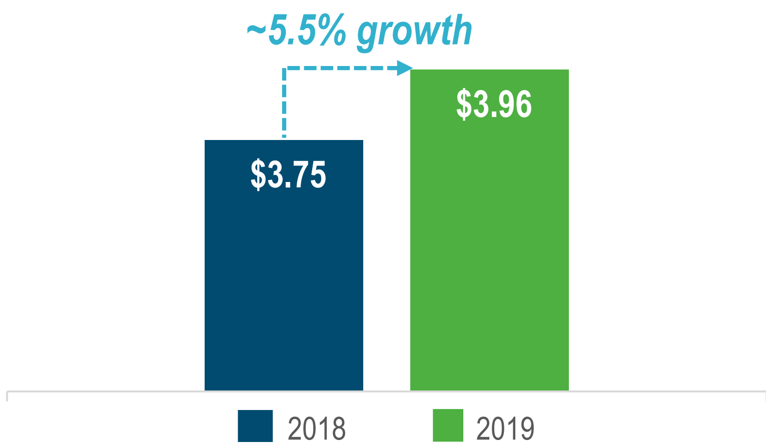
Demonstrated ability to grow core electric and gas earnings(1)

2017-2018 Full-year Adjusted Earnings(2)



Followed by…

2018-2019 YTD Q3 Adjusted Earnings



CORE ELECTRIC AND GAS FRANCHISES DELIVERING AT THE TOP END OF THE LONG-TERM ADJUSTED EARNINGS GROWTH RANGE SUPPORTED BY:

$37 BILLION GROWTH(3) CAPITAL PLAN 2019-2023

STRONG RESIDENTIAL CUSTOMER GROWTH

O&M COST CONTROL AND AGILITY

(1) Amounts include results of Electric Utilities and Infrastructure, Gas Utilities and Infrastructure and Other
(2) 2018 excludes $0.13 related to a lower tax shield as a result of the Tax Cuts and Jobs Act of 2017
(3) Amounts are approximately 95% core electric and gas utilities, with the remainder in Commercial Renewables

Reaffirming long-term earnings growth guidance

2020 PRIMARY GROWTH DRIVERS

***ALSO ENABLES EARNINGS GROWTH INTO 2021**

Electric Utilities & Infrastructure

- Florida multi-year rate plan and Solar BRA*
- Rate case activity to recover and earn on investments:
  - DEC/DEP SC: Q2 2019 (full year effect in 2020)
  - Indiana and Kentucky: mid-2020*
  - DEC NC: Q3 2020*
  - DEP NC: Q3 2020*
- Midwest grid investment riders (DEI/DEO)*
- Carolinas wholesale
- Load growth consistent with 0.5% long term expectation*
- O&M cost management through digital capabilities and other solutions*

Gas Utilities & Infrastructure

- Atlantic Coast Pipeline*
- Piedmont NC rate case and annual SC RSA filings
- Customer growth, integrity management investments, power generation gas infrastructure*

REAFFIRMING 4 - 6% EPS GROWTH THROUGH 2023[1]

(1) *Based on adjusted diluted EPS off the midpoint of the original 2019 guidance range, or $5.00*

Our investor value proposition

DUK
LISTED
NYSE

A SOLID LONG-TERM HOLDING

4.0%

DIVIDEND YIELD[1]
WITH DIVIDEND
GROWTH COMMITMENT[2]

~8-10%

ATTRACTIVE
RISK-ADJUSTED
TOTAL SHAREHOLDER RETURN[3]

4-6%

HIGHLY
ACHIEVABLE
EPS GROWTH THROUGH 2023[4]

CONSTRUCTIVE JURISDICTIONS, LOW-RISK REGULATED INVESTMENTS AND BALANCE SHEET STRENGTH

(1) As of November 6, 2019
(2) Subject to approval by the Board of Directors
(3) Total shareholder return proposition at a constant P/E ratio
(4) Based on adjusted diluted EPS off the midpoint of the original 2019 guidance range, or $5.00

Appendix

Financial supplement

Key 2019 adjusted earnings guidance assumptions

($ in millions)	Original 2019 Assumptions (1)	2019 YTD (thru 9/30/2019)
Adjusted segment income/(expense)(2):		
Electric Utilities & Infrastructure	$3,480	$2,925
Gas Utilities & Infrastructure	$375	$292
Commercial Renewables	$230	$139
Other	($440)	($328)
Duke Energy Consolidated	$3,645	$3,028
Additional consolidated information:		
Interest expense	$2,238	$1,657
Effective tax rate including noncontrolling interest and preferred dividends and excluding special items	12-14%	12.1%
Debt AFUDC and capitalized interest	$151	$115
AFUDC equity	$168	$99
Capital expenditures (3)(4)	$11,100	$8,840
Weighted-average shares outstanding	~729 million	~728 million

(1) Full year amounts for 2019, as disclosed on Feb. 14, 2019

(2) Adjusted net income for 2019 assumptions is based upon the midpoint of the original adjusted diluted EPS guidance range of $4.80 to $5.20

(3) Includes debt AFUDC and capitalized interest, except for ACP

(4) 2019 YTD (thru 9/30/2019) includes ~$560 million of coal ash closure spend that was included in operating cash flows and ~$120 million funded under the ACP revolving credit facility; excludes tax equity funding of commercial renewables projects of ~$190 million. 2019 Assumptions include ~$850 million of projected coal ash closure spend and $220 million projected to be funded under the ACP revolving credit facility

Key 2019 earnings sensitivities

Driver		EPS Impact
Electric Utilities & Infrastructure	1% change in earned return on equity	+/- $0.49
	$1 billion change in rate base	+/- $0.07
	1% change in volumes	+/- $0.13
Gas Utilities & Infrastructure	1% change in earned return on equity	+/- $0.06
	$200 million change in rate base	+/- $0.01
	1% change in number of new customers	+/- $0.01
Consolidated	1% change in interest rates[1]	+/- $0.07

Note: EPS amounts based on forecasted 2019 share count of ~729 million shares

(1) Based on average variable-rate debt outstanding throughout the year

Electric utilities quarterly weather impacts

Weather segment income to normal:	2019			2018		
	Pretax impact	Weighted avg. diluted shares	EPS impact favorable / (unfavorable)	Pretax impact	Weighted avg. shares	EPS impact favorable / (unfavorable)
First Quarter	($55)	727	($0.06)	$10	701	$0.01
Second Quarter	$80	728	$0.08	$90	704	$0.10
Third Quarter(1)	$145	729	$0.15	$55	714	$0.05
Fourth Quarter				$60	716	$0.06
Year-to-Date(1)(2)	$170	728	$0.17	$215	708	$0.22

3Q 2019	Duke Energy Carolinas		Duke Energy Progress		Duke Energy Florida		Duke Energy Indiana		Duke Energy Ohio/KY	
Heating degree days / Variance from normal	-	-	-	-	-	-	-	-	-	-
Cooling degree days / Variance from normal	1,205	21.8%	1,233	16.2%	1,545	4.0%	930	24.6%	1,026	36%

3Q 2018	Duke Energy Carolinas		Duke Energy Progress		Duke Energy Florida		Duke Energy Indiana		Duke Energy Ohio/KY	
Heating degree days / Variance from normal	-	-	-	-	-	-	37	(43.5%)	29	(48.0%)
Cooling degree days / Variance from normal	1,136	14.5%	1,217	15.6%	1,517	2.1%	896	20.0%	910	20.4%

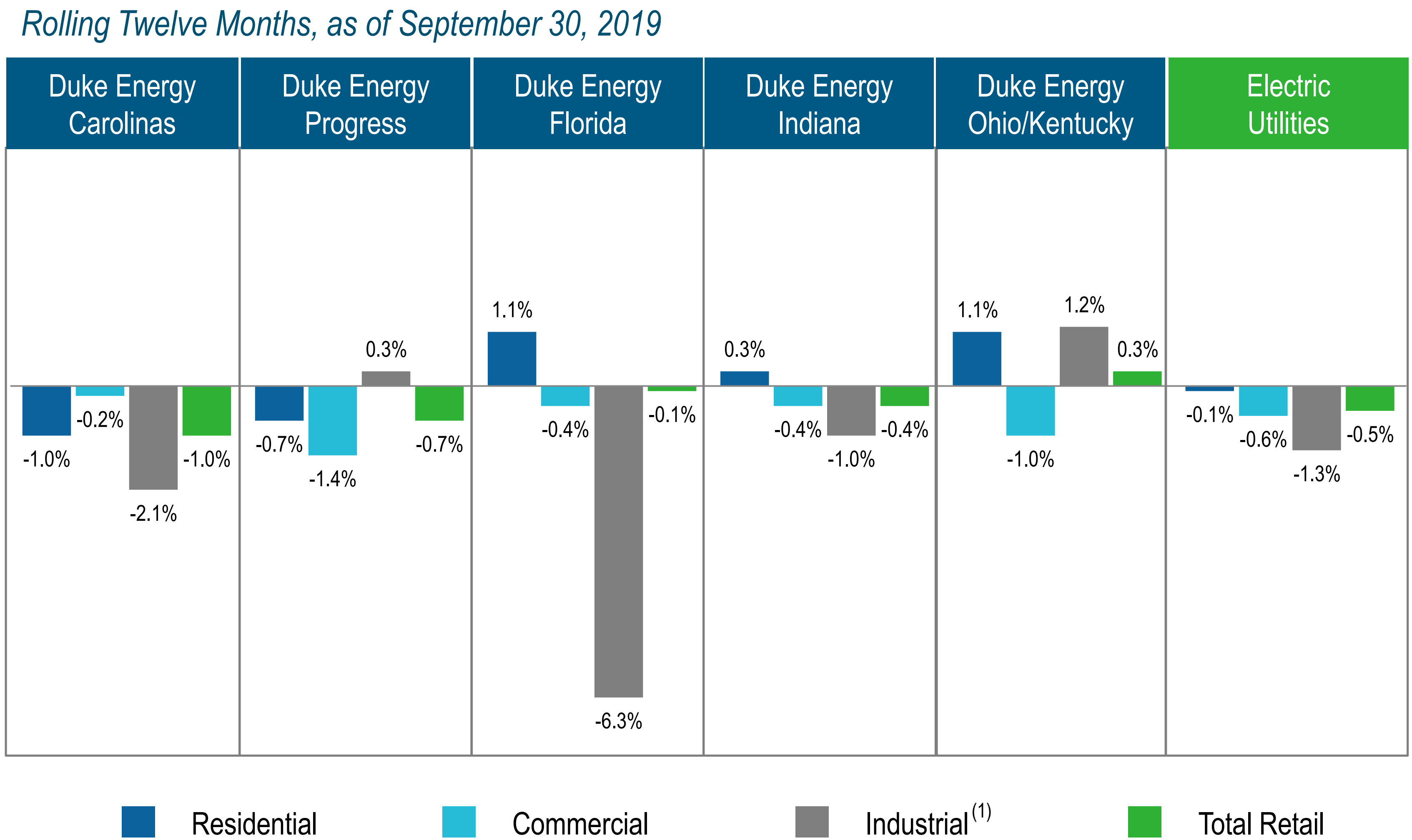
(1) 2018 includes an unfavorable ~$15 million or $0.01/share impact from Hurricane Florence
(2) Year-to-date amounts may not foot due to differences in weighted-average shares outstanding and/or rounding

Update on our regulatory activity

	FILING TYPE	DOCKET NO.	STATUS	KEY DRIVERS
DUKE ENERGY **CAROLINAS**	NC Base Rate Case filed Sep. 30, '19	E-7 Sub 1214	▪ Hearings scheduled Mar. '20 ▪ Requested new rates effective Aug. '20	▪ ROE 10.3%; 53% equity cap. structure ▪ Grid investments, including AMI ▪ Dual fuel plant upgrades ▪ Accelerated depreciation for coal plants ▪ Coal ash and storm costs(1)
DUKE ENERGY **PROGRESS**	NC Base Rate Case filed Oct. 30, '19	E-2 Sub 1219	▪ Hearings expected early '20 ▪ Requested new rates effective Sep. '20	▪ ROE 10.3%; 53% equity cap. structure ▪ Grid investments, including AMI ▪ Western Carolinas Modernization Project ▪ Nuclear plant investments ▪ Accelerated depreciation for coal plants ▪ Coal ash and storm costs(1)
PIEDMONT NATURAL GAS	NC Base Rate Case	G-9 Sub 743	▪ NCUC approved settlement agreement on Oct. 31,'19 ▪ Rates effective Nov. 1, '19	▪ ROE 9.7%; 52% equity cap. structure
	SC Rate Stabilization Act ("RSA")	2019-7-G	▪ PSCSC approved Oct. '19 ▪ Rates effective Nov. '19	▪ ROE 9.9%; 55% equity cap. structure
DUKE ENERGY **INDIANA**	Base Rate Case filed July 2, '19	No. 45253	▪ Hearings expected 1Q '20 ▪ Requested new rates effective mid-'20	▪ ROE 10.4%; 53% equity cap. structure ▪ Grid investments ▪ Accelerated depreciation for coal plants ▪ Coal ash costs ▪ Includes modernized regulatory mechanisms
DUKE ENERGY **KENTUCKY**	Base Rate Case filed Sep. 3, '19	2019-00271	▪ Hearings expected 1Q '20 ▪ Requested new rates effective Q2 '20	▪ ROE 9.8%; 48% equity cap. structure ▪ Investments in distribution system to support localized load growth and dual fuel capability

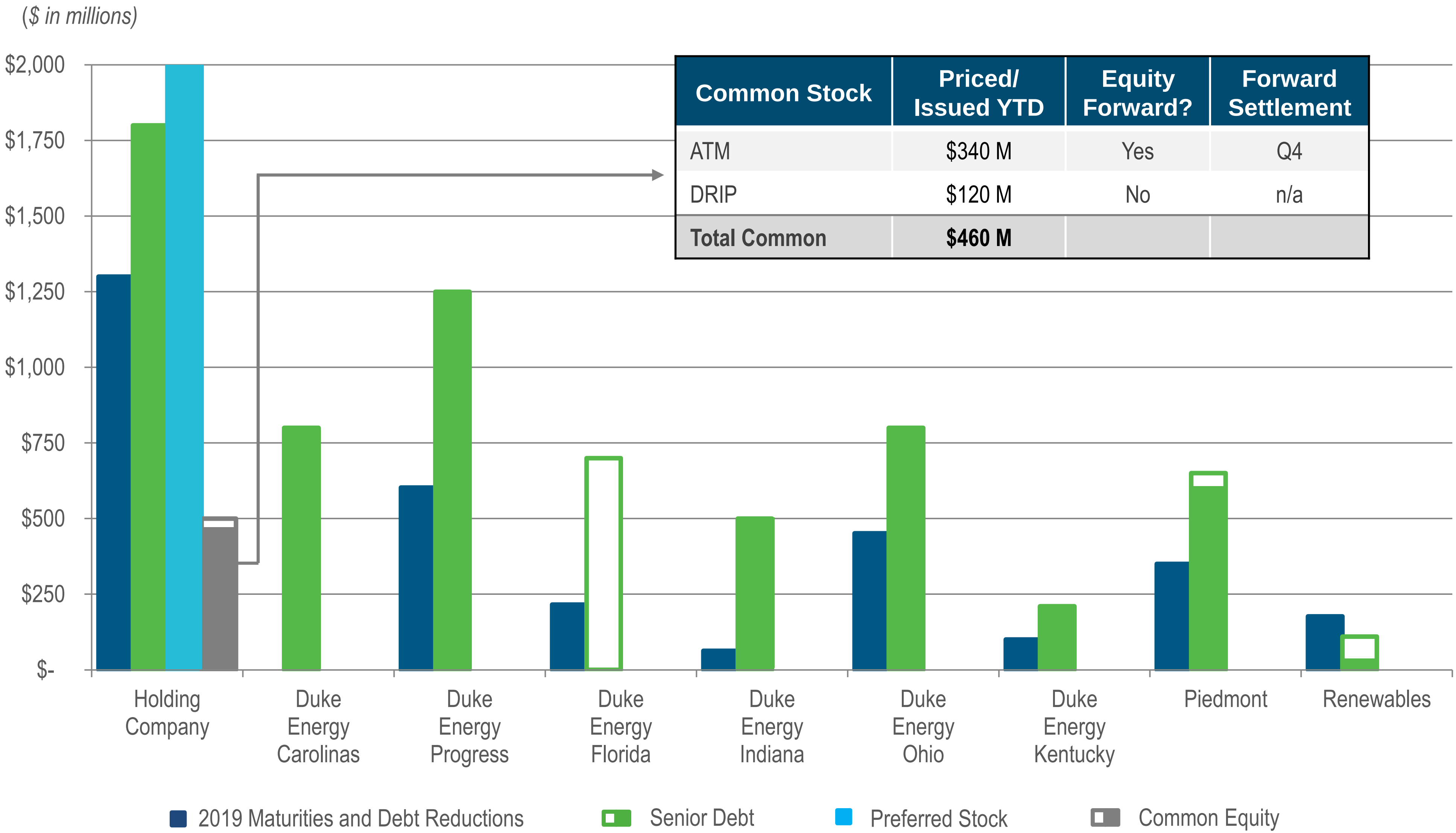
(1) With passage of SB559 (legislation for storm securitization) DEC and DEP will seek to securitize these costs

Weather normalized volume trends, by electric jurisdiction



(1) *Electric Utilities industrial results have been impacted by production interruptions at a couple of large customers*

2019 financing plan as of September 30, 2019 (1)



Common Stock	Priced/ Issued YTD	Equity Forward?	Forward Settlement
ATM	$340 M	Yes	Q4
DRIP	$120 M	No	n/a
Total Common	**$460 M**		

(1) *Represents progress made toward the expected long-term debt, preferred stock and common equity capital raising during 2019*

2019 long-term debt and preferred stock financing activity as of September 30, 2019

Amount ($ in millions)	Entity	Date Issued	Credit Ratings (M/S&P/F, unless otherwise noted)	Term	Type	Rate
$400	DE Ohio	January 2019	A2/A	10-Year	First Mortgage Bond	Fixed – 3.65%
$400	DE Ohio	January 2019	A2/A	30-Year	First Mortgage Bond	Fixed – 4.30%
$650	DE Progress	Jan. & Feb. 2019	A2/A-(1)	2-Year	Term Loan	Floating
$600	DE Progress	March 2019	Aa3/A	10-year	First Mortgage Bond	Fixed – 3.45%
$300	DE Corp.	March 2019	Baa1/BBB+	3-Year	Senior Unsecured Notes	Fixed – 3.227%
$300	DE Corp.	March 2019	Baa1/BBB+	3-Year	Senior Unsecured Notes	Floating
$1,000	DE Corp.	March 2019	Baa3/BBB/BBB-	Perpetual	Preferred Stock	Fixed – 5.75%
$600	Piedmont	May 2019	A3/A-	10-Year	Senior Unsecured Notes	Fixed – 3.50%
$600	DE Corp.	June 2019	Baa1/BBB+/BBB+	10-Year	Senior Unsecured Notes	Fixed – 3.40%
$600	DE Corp.	June 2019	Baa1/BBB+/BBB+	30-Year	Senior Unsecured Notes	Fixed – 4.20%
$40	DE Kentucky	June 2019	N/A (2)	30-Year	Debentures	Fixed – 4.32%
$75	DE Kentucky	Sept 2019	N/A (2)	10-Year	Debentures	Fixed – 3.56%
$95	DE Kentucky	Sept 2019	N/A (2)	6-Year	Debentures	Fixed – 3.23%
$450	DE Carolinas	August 2019	Aa2/A	10-Year	First Mortgage Bond	Fixed – 2.45%
$350	DE Carolinas	August 2019	Aa2/A	30-Year	First Mortgage Bond	Fixed – 3.20%
$500	DE Indiana	Sept 2019	Aa3/A	30-Year	First Mortgage Bond	Fixed – 3.25%
$1,000	DE Corp.	Sept 2019	Baa3/BBB/BBB-	Perpetual	Preferred Stock	Fixed – 4.875%

(1) Represents the Issuer/Corporate Credit Ratings
(2) Issuance privately placed

Liquidity summary as of September 30, 2019

	Duke Energy	Duke Energy Carolinas	Duke Energy Progress	Duke Energy Florida	Duke Energy Indiana	Duke Energy Ohio	Duke Energy Kentucky	Piedmont Natural Gas	Total
Master Credit Facility [(1)]	$ 2,650	$ 1,750	$ 1,250	$ 800	$ 600	$ 300	$ 150	$ 500	$ 8,000
Less: Notes payable and commercial paper [(2)]	(627)	(338)	(211)	(277)	(150)	(139)	(25)	(204)	(1,971)
Coal Ash Set-Aside	-	(250)	(250)	-	-	-	-	-	(500)
Outstanding letters of credit (LOCs)	(43)	(4)	(2)	-	-	-	-	(2)	(51)
Tax-exempt bonds	-	-	-	-	(81)	-	-	-	(81)
Available capacity	$ 1,980	$ 1,158	$ 787	$ 523	$ 369	$ 161	$ 125	$ 294	$ 5,397
Funded Revolver and Term Loan [(3)]	$ 1,000		$ 700						$ 1,700
Less: Borrowings Under Credit Facilities	(500)		(700)						(1,200)
Available capacity	$ 500	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 500
Cash & short-term investments									266
Total available liquidity									**$ 6,163**

Note: excludes variable denomination floating-rate demand notes, called PremierNotes. At September 30, 2019, the PremierNotes balance was $1,019 million

(1) Master Credit Facility supports tax-exempt put bonds, LOCs and the Duke Energy commercial paper program of $4.85 billion

(2) Includes permanent layer of commercial paper of $625 million, which is classified as long-term debt

(3) Borrowings under these facilities will be used for general corporate purposes

Credit ratings (as of September 30, 2019)

Holding Companies

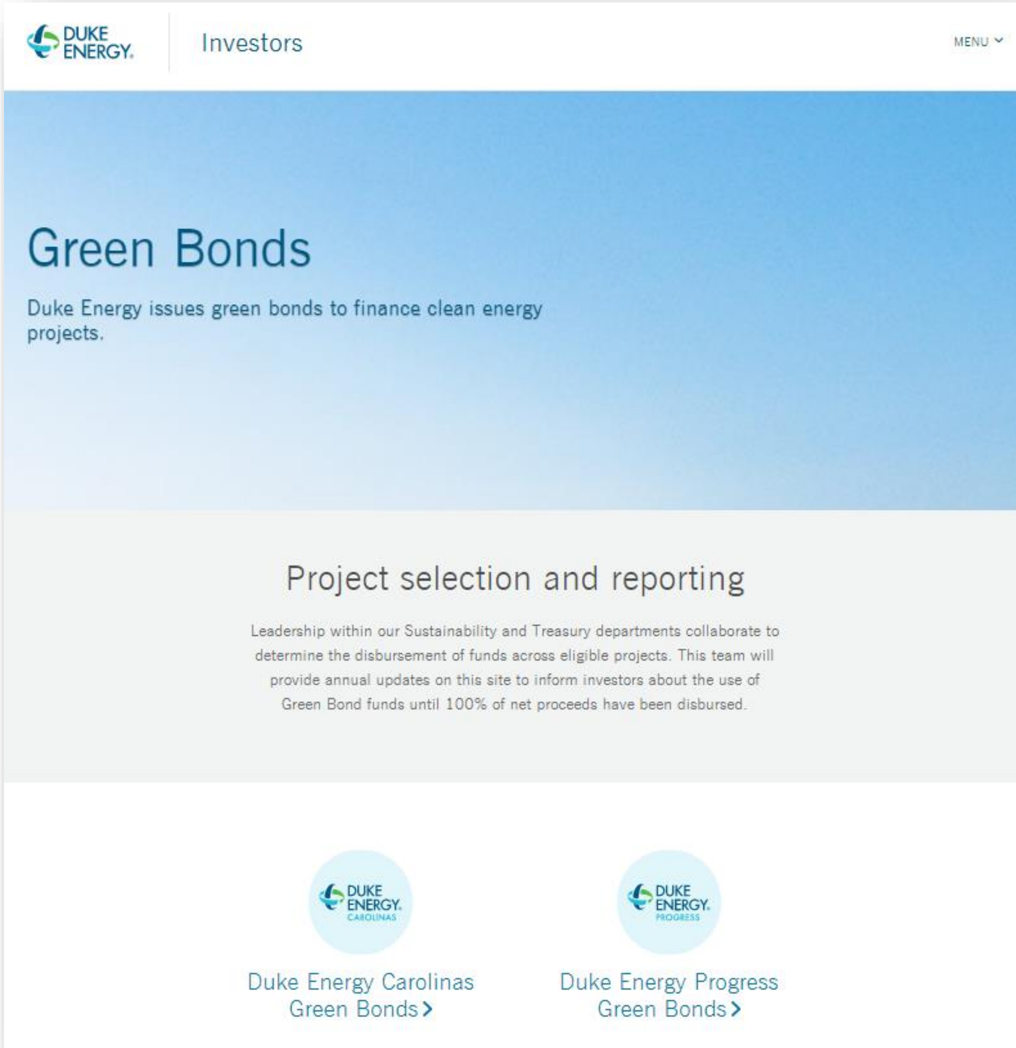
	Moody's	S&P	Fitch
DUKE ENERGY CORPORATION	Stable	Negative	Stable
Senior Unsecured Debt	Baa1	BBB+	BBB+
Commercial Paper	P-2	A-2	F-2
PROGRESS ENERGY, INC.	Stable	Negative	
Senior Unsecured Debt	Baa1	BBB+	

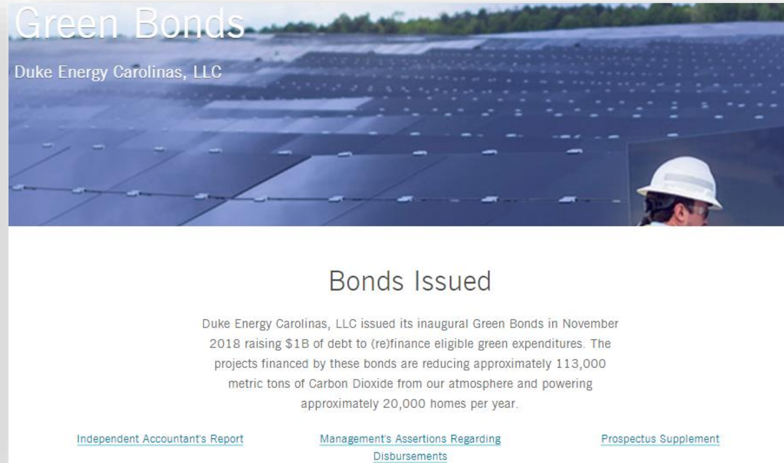
Operating Companies

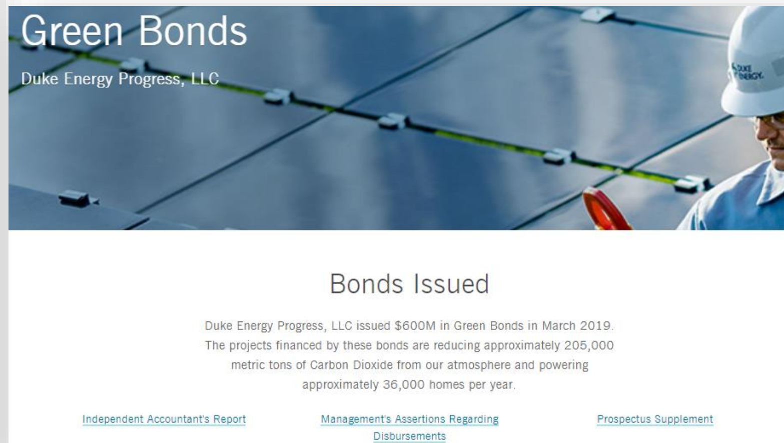
	Moody's	S&P
DUKE ENERGY CAROLINAS, LLC	Stable	Negative
Senior Secured Debt	Aa2	A
Senior Unsecured Debt	A1	A-
DUKE ENERGY PROGRESS, LLC	Stable	Negative
Senior Secured Debt	Aa3	A
DUKE ENERGY FLORIDA, LLC	Stable	Negative
Senior Secured Debt	A1	A
Senior Unsecured Debt	A3	A-
DUKE ENERGY INDIANA, LLC	Stable	Negative
Senior Secured Debt	Aa3	A
Senior Unsecured Debt	A2	A-
DUKE ENERGY OHIO, INC.	Stable	Negative
Senior Secured Debt	A2	A
Senior Unsecured Debt	Baa1	A-
DUKE ENERGY KENTUCKY, INC.	Stable	Negative
Senior Unsecured Debt	Baa1	A-
PIEDMONT NATURAL GAS, INC.	Stable	Negative
Senior Unsecured Debt	A3	A-

Recently launched green bond website

www.duke-energy.com/our-company/investors/green-bonds







Sustainability / Environmental Social and Governance (ESG)

Sustainability / Environmental Social and Governance (ESG)

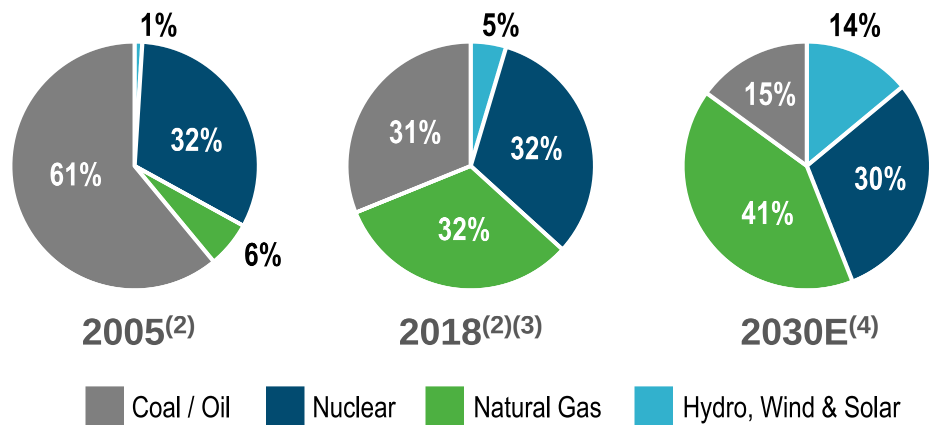
CARBON AND OTHER REDUCTIONS

OTHER ESG FOCUS AREAS

INDUSTRY LEADING DISCLOSURE

- Targeting at least 50% reduction in carbon dioxide (CO_2) emissions by 2030(1); net-zero by mid-century
- Since 2005, decreased CO_2 emissions by 31%, sulfur dioxide emissions by 96% and nitrogen oxides emissions by 74%
- 49 coal units retired (~6.2 GW) since 2010
- As of year-end 2018, owned or contracted 7,100 MW of renewables
- Targeting 1 trillion gallon reduction in water withdrawals by our generation fleet by 2030 (from 5.34 trillion gallons in 2016)

FUEL DIVERSITY (MWh OUTPUT)



(1) *From 2005 levels*
(2) *2005 and 2018 data based on Duke's ownership share of U.S. generation assets as of Dec. 31, 2018*
(3) *2018 data excludes 8,519 GWh of purchased renewables, equivalent to ~4% of Duke's output*
(4) *Percentages in the 2030E pie chart not yet updated for the impact of the new climate goal announced Sept. 2019. 2030 estimate will be influenced by customer demand for electricity, weather, fuel availability and prices*

Sustainability / Environmental Social and Governance (ESG)

CARBON AND OTHER REDUCTIONS

OTHER ESG FOCUS AREAS

INDUSTRY LEADING DISCLOSURE

SAFETY – OUR NUMBER ONE PRIORITY

- Total Incident Case Rate (TICR) of 0.43 in 2018; one of the industry leaders for 4th year in a row

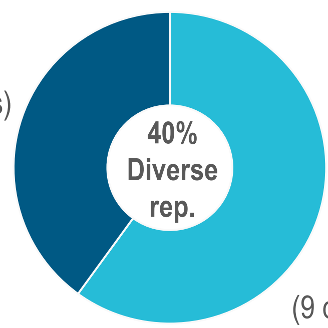
EMPLOYEES

- Targeting a companywide engagement score of 76% by 2022
- Named one of "America's Best Employers" by Forbes in 2019
- Named one of the "50 Best Companies for Diversity" by Black Enterprise magazine in 2018

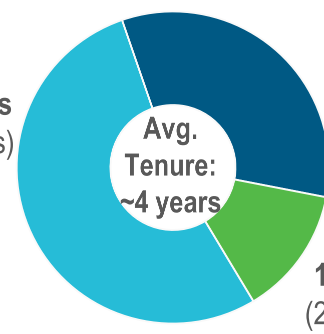
GOVERNANCE

- Oversight of sustainability formally added to Corporate Governance Committee of the Duke Energy Board of Directors charter in 2018

BOARD DIVERSITY



BOARD TENURE



(1) Racial, gender and ethnic diversity

Sustainability / Environmental Social and Governance (ESG)

CARBON AND OTHER REDUCTIONS

OTHER ESG FOCUS AREAS

INDUSTRY LEADING DISCLOSURE

- Dow Jones Sustainability Index for 14 years in a row
- Over a decade of annual Sustainability reports
- Climate Report issued in 2018 analyzes 2-degree scenario
  - Our 50% CO_2 reduction goal is consistent with a pathway to achieve a 2-degree target
- EEI / AGA reporting templates provide investors greater uniformity and consistency in reporting of ESG metrics
- 2019 Winner of U.S. Transparency Award by Labrador Group for utilities
- Bloomberg ESG disclosure score of 56.6, the second-best score and in the top decile of our peer U.S. utilities[1]

see more at: **www.duke-energy.com/our-company/sustainability**

(1) *As of March 29, 2019*

Other supplemental information

Advancing our strategic vision

TRANSFORM THE
CUSTOMER EXPERIENCE

MODERNIZE THE
ENERGY GRID

GENERATE
CLEANER ENERGY

EXPAND **NATURAL GAS**
INFRASTRUCTURE

STAKEHOLDER
ENGAGEMENT

EMPLOYEE ENGAGEMENT AND OPERATIONAL EXCELLENCE
ARE FOUNDATIONAL TO OUR SUCCESS

Renewables project announcements

		Megawatts					
	Site	Solar	Wind	Fuel Cell	Total	COD	Location
Regulated:	Lake Placid	45	-	-	45	Q4 2019	FL
	Trenton	74.9	-	-	74.9	Q4 2019	FL
	DeBary	74.5	-	-	74.5	Q1 2020	FL
	Columbia	74.9	-	-	74.9	Q1 2020	FL
	Catawba County(1)	69	-	-	69	2020	NC (DEC)
	Gaston County(1)	25	-	-	25	2020	NC (DEC)
	PPA projects(1)(2)	362	-	-	362	2020/2021	NC/SC
Subtotal – Regulated		**726**	**-**	**-**	**726**		
Commercial:	Cleveland County(1)	50	-	-	50	2020	NC
	Surry County(1)	23	-	-	23	2020	NC
	Cabarrus County(1)	23	-	-	23	2020	NC
	Rosamond	150	-	-	150	Q2 2019	CA
	Lapetus	100	-	-	100	Q4 2019	TX
	Palmer	60	-	-	60	Q4 2019	CO
	Holstein	200	-	-	200	2020	TX
	Rambler(3)	**200**	**-**	**-**	**200**	**2020**	**TX**
	Mesteno	-	200	-	200	Q4 2019	TX
	Frontier II	-	350	-	350	2020	OK
	Maryneal(3)	**-**	**180**	**-**	**180**	**2020**	**TX**
	Bloom Energy	-	-	37	37	2019/2020	Various
Subtotal – Commercial(4)		**806**	**730**	**37**	**1,573**		
GRAND TOTAL - announced		**1,532**	**730**	**37**	**2,299**		

(1) Projects that cleared the first RFP under HB589 (552 MW in total). Dates may vary depending upon local approvals and any construction delays
(2) Projects procured on behalf of customers but not owned by Duke Energy
(3) Projects announced in third quarter 2019
(4) Approximately 1/3 of capital requirement to be funded with tax equity

Coal ash closure costs[1]

NCDEQ COAL ASH ORDER

- NC DEQ issued order April 1 requiring low priority sites be fully excavated
  - Incremental cost of $4 - 5 billion vs. cap-in-place / hybrid closure methods would be spent over decades
  - Coal ash closure costs would increase $200 – $400 million over 5-year plan (<1% of total capital plan)
- Company appealed the decision to the NC Office of Administrative Hearings on April 26; expect process to last well into 2020

($ in millions)

Category	2019 – 2023
Waste (closure)	$2,380
All other environmental	$400
Total	**$2,780**

Coal Ash Closure Costs	Total Project Costs[1]	Spend Through 2018	2019 – 2023 Plan[1]
Duke Energy Carolinas	$2,760	$950	$730
Duke Energy Progress	$2,900	$700	$1,190
Duke Energy Indiana	$930	$150	$425
Duke Energy Florida	$25	--	$5
Duke Energy Kentucky	$75	$15	$30
Total	**$6,690**	**$1,815**	**$2,380**

(1) *Tables shown are as disclosed in the Fourth Quarter 2018 Earnings Review and Business Update on Feb. 14, 2019 and do not include the impact of NC DEQ's April 1, 2019 order*

Upcoming events & other

Upcoming events

Event	Date
EEI Financial Conference	November 10-12, 2019
4Q 2019 Earnings Call (tentative)	February 13, 2020

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Safe harbor statement

This document includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are based on management's beliefs and assumptions and can often be identified by terms and phrases that include "anticipate," "believe," "intend," "estimate," "expect," "continue," "should," "could," "may," "plan," "project," "predict," "will," "potential," "forecast," "target," "guidance," "outlook" or other similar terminology. Various factors may cause actual results to be materially different than the suggested outcomes within forward-looking statements; accordingly, there is no assurance that such results will be realized. These factors include, but are not limited to: State, federal and foreign legislative and regulatory initiatives, including costs of compliance with existing and future environmental requirements, including those related to climate change, as well as rulings that affect cost and investment recovery or have an impact on rate structures or market prices; The extent and timing of costs and liabilities to comply with federal and state laws, regulations and legal requirements related to coal ash remediation, including amounts for required closure of certain ash impoundments, are uncertain and difficult to estimate; The ability to recover eligible costs, including amounts associated with coal ash impoundment retirement obligations and costs related to significant weather events, and to earn an adequate return on investment through rate case proceedings and the regulatory process; The costs of decommissioning Crystal River Unit 3 and other nuclear facilities could prove to be more extensive than amounts estimated and all costs may not be fully recoverable through the regulatory process; Costs and effects of legal and administrative proceedings, settlements, investigations and claims; Industrial, commercial and residential growth or decline in service territories or customer bases resulting from sustained downturns of the economy and the economic health of our service territories or variations in customer usage patterns, including energy efficiency efforts and use of alternative energy sources, such as self-generation and distributed generation technologies; Federal and state regulations, laws and other efforts designed to promote and expand the use of energy efficiency measures and distributed generation technologies, such as private solar and battery storage, in Duke Energy service territories could result in customers leaving the electric distribution system, excess generation resources as well as stranded costs; Advancements in technology; Additional competition in electric and natural gas markets and continued industry consolidation; The influence of weather and other natural phenomena on operations, including the economic, operational and other effects of severe storms, hurricanes, droughts, earthquakes and tornadoes, including extreme weather associated with climate change; The ability to successfully operate electric generating facilities and deliver electricity to customers including direct or indirect effects to the company resulting from an incident that affects the U.S. electric grid or generating resources; The ability to obtain the necessary permits and approvals and to complete necessary or desirable pipeline expansion or infrastructure projects in our natural gas business; Operational interruptions to our natural gas distribution and transmission activities; The availability of adequate interstate pipeline transportation capacity and natural gas supply; The impact on facilities and business from a terrorist attack, cybersecurity threats, data security breaches, operational accidents, information technology failures or other catastrophic events, such as fires, explosions, pandemic health events or other similar occurrences; The inherent risks associated with the operation of nuclear facilities, including environmental, health, safety, regulatory and financial risks, including the financial stability of third-party service providers; The timing and extent of changes in commodity prices and interest rates and the ability to recover such costs through the regulatory process, where appropriate, and their impact on liquidity positions and the value of underlying assets; The results of financing efforts, including the ability to obtain financing on favorable terms, which can be affected by various factors, including credit ratings, interest rate fluctuations, compliance with debt covenants and conditions and general market and economic conditions; Credit ratings of the Duke Energy Registrants may be different from what is expected; Declines in the market prices of equity and fixed-income securities and resultant cash funding requirements for defined benefit pension plans, other post-retirement benefit plans and nuclear decommissioning trust funds; Construction and development risks associated with the completion of the Duke Energy Registrants' capital investment projects, including risks related to financing, obtaining and complying with terms of permits, meeting construction budgets and schedules and satisfying operating and environmental performance standards, as well as the ability to recover costs from customers in a timely manner, or at all; Changes in rules for regional transmission organizations, including changes in rate designs and new and evolving capacity markets, and risks related to obligations created by the default of other participants; The ability to control operation and maintenance costs; The level of creditworthiness of counterparties to transactions; Employee workforce factors, including the potential inability to attract and retain key personnel; The ability of subsidiaries to pay dividends or distributions to Duke Energy Corporation holding company (the Parent); The performance of projects undertaken by our nonregulated businesses and the success of efforts to invest in and develop new opportunities; The effect of accounting pronouncements issued periodically by accounting standard-setting bodies; The impact of U.S. tax legislation to our financial condition, results of operations or cash flows and our credit ratings; The impacts from potential impairments of goodwill or equity method investment carrying values; and The ability to implement our business strategy, including enhancing existing technology systems.

Additional risks and uncertainties are identified and discussed in the Duke Energy Registrants' reports filed with the SEC and available at the SEC's website at sec.gov. In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than described. Forward-looking statements speak only as of the date they are made and the Duke Energy Registrants expressly disclaim an obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

BUILDING A **SMARTER** ENERGY FUTURE ®

For additional information on Duke Energy,
please visit: duke-energy.com/investors

Duke Energy Corporation
Non-GAAP Reconciliations
Third Quarter Earnings Review & Business Update
November 8, 2019

Adjusted Diluted Earnings per Share (EPS)

The materials for Duke Energy Corporation's (Duke Energy) Third Quarter Earnings Review and Business Update on November 8, 2019, include a discussion of adjusted diluted EPS for the quarter and year-to-date periods ended September 30, 2019 and 2018.

The non-GAAP financial measure, adjusted diluted EPS, represents diluted EPS from continuing operations attributable to Duke Energy Corporation common stockholders, adjusted for the per share impact of special items. As discussed below, special items represent certain charges and credits, which management believes are not indicative of Duke Energy's ongoing performance.

The most directly comparable GAAP measure for adjusted diluted EPS is reported diluted EPS attributable to Duke Energy Corporation common stockholders. Reconciliations of adjusted diluted EPS for the quarter and year-to-date periods ended September 30, 2019 and 2018, to the most directly comparable GAAP measures are included herein.

Special items for the quarter and year-to-date periods ended September 30, 2019 and 2018, include the following items, which management believes do not reflect ongoing costs:

- Impairment Charges represents a reduction of a prior-year impairment at Citrus County CC, an other-than-temporary-impairment ("OTTI") of an investment in Constitution and a Commercial Renewables goodwill impairment.
- Costs to Achieve Piedmont Merger represents charges that resulted from the Piedmont acquisition.
- Regulatory and Legislative Impacts represents charges related to rate case orders, settlements or other actions of regulators or legislative bodies.
- Sale of Retired Plant represents the loss associated with selling Beckjord, a nonregulated generating facility in Ohio.
- Impacts of the Tax Act represents an AMT valuation allowance recognized and a true up of prior-year tax estimates related to the Tax Act.

Adjusted Diluted EPS Guidance

The materials for Duke Energy's Third Quarter Earnings Review and Business Update on November 8, 2019, include a reference to the forecasted 2019 adjusted diluted EPS guidance range of $4.95 - $5.25 per share, narrowed from $4.80 - $5.20 per share during the third quarter of 2019. The materials also reference the long-term range of annual growth of 4% - 6% through 2023 off the original midpoint of 2019 adjusted EPS guidance range of $5.00. Adjusted diluted EPS is a non-GAAP financial measure as it represents diluted EPS from continuing operations attributable to Duke Energy Corporation common stockholders, adjusted for the per share impact of special items (as discussed above under Adjusted Diluted EPS). Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items for future periods, such as legal settlements, the impact of regulatory orders or asset impairments.

Adjusted Segment Income and Adjusted Other Net Loss

The materials for Duke Energy's Third Quarter Earnings Review and Business Update on November 8, 2019, include a discussion of adjusted segment income and adjusted other net loss for the quarter and year-to-date periods ended September 30, 2019 and 2018, and a discussion of 2019 forecasted adjusted segment income and forecasted adjusted other net loss.

Adjusted segment income and adjusted other net loss are non-GAAP financial measures, as they represent reported segment income and other net loss adjusted for special items (as discussed above under Adjusted Diluted EPS). When a per share impact is provided for a segment income driver, the after-tax driver is derived using the pretax amount of the item less income taxes based on the segment statutory tax rate of 24% for Electric Utilities and Infrastructure and Gas Utilities and Infrastructure, segment statutory tax rate of 23% for Other, or an effective tax rate for Commercial Renewables. The after-tax earnings drivers are divided by the Duke Energy weighted average diluted shares outstanding for the period. The most directly comparable GAAP measures for adjusted segment income and adjusted other net loss are reported segment income and other net loss, which represents segment income and other net loss from continuing operations, including any special items. A reconciliation of adjusted segment income and adjusted other net loss for the quarter and year-to-date periods ended September 30, 2019 and 2018, to the most directly comparable GAAP measures is included herein. Due to the forward-looking nature of any forecasted adjusted segment income and forecasted other net loss and any related growth rates for future periods, information to reconcile these non-GAAP financial measures to the most directly comparable GAAP financial measures are not available at this time, as the company is unable to forecast all special items, as discussed above under Adjusted Diluted EPS guidance.

Effective Tax Rate Including Impacts of Noncontrolling Interests and Preferred Dividends and Excluding Special Items

The materials for Duke Energy's Third Quarter Earnings Review and Business Update on November 8, 2019, include a discussion of the effective tax rate including impacts of noncontrolling interests and preferred dividends and excluding special items for the quarter and year-to-date periods ended September 30, 2019. The materials also include a discussion of the 2019 forecasted effective tax rate including impacts of noncontrolling interests and preferred dividends and excluding special items. Effective tax rate including impacts of noncontrolling interests and preferred dividends and excluding special items is a non-GAAP financial measure as the rate is calculated using pretax income and income tax expense, both adjusted for the impact of special items, noncontrolling interests and preferred dividends. The most directly comparable GAAP measure is reported effective tax rate, which includes the impact of special items and excludes the impacts of noncontrolling interests and preferred dividends. A reconciliation of this non-GAAP financial measure for the quarter and year-to-date periods ended September 30, 2019, to the most directly comparable GAAP measure is included herein. Due to the forward-looking nature of the 2019 forecasted effective tax rate including impacts of noncontrolling interests and preferred dividends and excluding special items, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items, as discussed above under Adjusted Diluted EPS Guidance.

Available Liquidity

The materials for Duke Energy's Third Quarter Earnings Review and Business Update on November 8, 2019, include a discussion of Duke Energy's available liquidity balance. The available liquidity balance presented is a non-GAAP financial measure as it represents cash and cash equivalents, excluding certain amounts held in foreign jurisdictions and cash otherwise unavailable for operations, and remaining availability under Duke Energy's available credit facilities, including the master credit facility. The most directly comparable GAAP financial measure for available liquidity is cash and cash equivalents. A reconciliation of available liquidity as of September 30, 2019, to the most directly comparable GAAP measure is included herein.

Core Electric and Gas Earnings per Share

The materials for Duke Energy's Third Quarter Earnings Review and Business Update on November 8, 2019, reference Core Electric and Gas Earnings per Share for the year-to-date periods ended September 30, 2019 and 2018, and December 31, 2018 and 2017. The Core Electric and Gas Earnings per Share is calculated by adding Adjusted Earnings per segment, excluding the Commercial Renewables segment, and dividing by the total weighted average shares, diluted (reported and adjusted).

Core Electric and Gas Earnings per Share is a non-GAAP financial measure, as it represents reported diluted EPS adjusted for special items. Special items represent certain charges and credits, which management believes are not indicative of Duke Energy's ongoing performance (as discussed above under Adjusted Diluted EPS). The most directly comparable GAAP measure for adjusted diluted EPS is reported diluted EPS attributable to Duke Energy Corporation common stockholders. Reconciliations of adjusted diluted EPS for the year-to-date periods ended September 30, 2019 and 2018, and December 31, 2018 and 2017, to the most directly comparable GAAP measures are included herein.

Non-Rider Recoverable O&M

The materials for Duke Energy's Third Quarter Earnings Review and Business Update on November 8, 2019, include a discussion of Duke Energy's non-rider recoverable operating, maintenance and other expenses (O&M) for the year-to-date periods ended December 31, 2018, 2017, 2016 and 2015 as well as the forecasted year-to-date period ended December 31, 2019. Non-rider recoverable O&M expenses are non-GAAP financial measures, as they represent reported O&M expenses adjusted for special items and expenses recovered through riders. The most directly comparable GAAP financial measure for non-rider recoverable O&M expenses is reported operating, maintenance and other expenses. A reconciliation of nonrecoverable O&M expenses for the year-to-date periods ended December 31, 2018, 2017, 2016, and 2015, as well as the forecasted year-to-date period ended December 31, 2019, to the most directly comparable GAAP measure are included here-in. Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items, as discussed above under Adjusted Diluted EPS Guidance.

DUKE ENERGY CORPORATION
REPORTED TO ADJUSTED EARNINGS RECONCILIATION
Three Months Ended September 30, 2019
(Dollars in millions, except per-share amounts)

		Special Item		
	Reported Earnings	**Impairment Charge**	**Total Adjustments**	**Adjusted Earnings**
SEGMENT INCOME				
Electric Utilities and Infrastructure	**$ 1,385**	$ (19) **A**	$ (19)	$ 1,366
Gas Utilities and Infrastructure	**26**	—	—	26
Commercial Renewables	**40**	—	—	40
Total Reportable Segment Income	**1,451**	**(19)**	**(19)**	**1,432**
Other	**(124)**	—	—	(124)
Net Income Attributable to Duke Energy Corporation	**$ 1,327**	**$ (19)**	**$ (19)**	**$ 1,308**
EPS ATTRIBUTABLE TO DUKE ENERGY CORPORATION, DILUTED	**$ 1.82**	**$ (0.03)**	**$ (0.03)**	**$ 1.79**

A — Net of $6 million tax expense. $25 million reduction of a prior year impairment recorded within Impairment charges on Duke Energy Florida's Condensed Consolidated Statements of Operations.

Weighted Average Shares, Diluted (reported and adjusted) — 729 million

DUKE ENERGY CORPORATION
REPORTED TO ADJUSTED EARNINGS RECONCILIATION
Nine Months Ended September 30, 2019
(Dollars in millions, except per-share amounts)

	Reported Earnings	Special Item: Impairment Charge	Total Adjustments	Adjusted Earnings
SEGMENT INCOME				
Electric Utilities and Infrastructure	**$ 2,944**	$ (19) **A**	$ (19)	$ 2,925
Gas Utilities and Infrastructure	**292**	—	—	292
Commercial Renewables	**139**	—	—	139
Total Reportable Segment Income	**3,375**	**(19)**	**(19)**	**3,356**
Other	**(328)**		—	(328)
Net Income Attributable to Duke Energy Corporation	**$ 3,047**	**$ (19)**	**$ (19)**	**$ 3,028**
EPS ATTRIBUTABLE TO DUKE ENERGY CORPORATION, DILUTED	**$ 4.18**	**$ (0.03)**	**$ (0.03)**	**$ 4.15**

A — Net of $6 million tax expense. $25 million reduction of a prior year impairment recorded within Impairment charges on Duke Energy Florida's Condensed Consolidated Statements of Operations.

Weighted Average Shares, Diluted (reported and adjusted) — 728 million

DUKE ENERGY CORPORATION
REPORTED TO ADJUSTED EARNINGS RECONCILIATION
Three Months Ended September 30, 2018
(Dollars in millions, except per-share amounts)

		Special Items					
	Reported Earnings	Costs to Achieve Piedmont Merger	Impairment Charges	Impacts of the Tax Act	Discontinued Operations	Total Adjustments	Adjusted Earnings
SEGMENT INCOME							
Electric Utilities and Infrastructure	**$ 1,167**	$ —	$ —	$ 8	$ —	$ 8	$ 1,175
Gas Utilities and Infrastructure	**17**	—	—	1	—	1	18
Commercial Renewables	**(62)**	—	91 **B**	(3)	—	88	26
Total Reportable Segment Income	**1,122**	**—**	**91**	**6**	**—**	**97**	**1,219**
Other	**(44)**	13 **A**	—	(9)	—	4	(40)
Discontinued Operations	**4**	—	—	—	(4) **D**	(4)	—
Net Income Attributable to Duke Energy Corporation	**$ 1,082**	**$ 13**	**$ 91**	**$ (3) C**	**$ (4)**	**$ 97**	**$ 1,179**
EPS ATTRIBUTABLE TO DUKE ENERGY CORPORATION, DILUTED	**$ 1.51**	**$ 0.02**	**$ 0.12**	**$ —**	**$ —**	**$ 0.14**	**$ 1.65**

A — Net of $3 million tax benefit. $16 million recorded within Operating Expenses on the Condensed Consolidated Statements of Operations.

B — Net of $2 million Noncontrolling Interests. $93 million goodwill impairment recorded within Impairment charges on the Condensed Consolidated Statements of Operations.

C — $3 million tax benefit true up of prior year Tax Act estimates recorded within Income Tax Expense from Continuing Operations on the Condensed Consolidated Statements of Operations.

D — Recorded in Income (Loss) from Discontinued Operations, net of tax on the Condensed Consolidated Statements of Operations.

Weighted Average Shares, Diluted (reported and adjusted) — 714 million

DUKE ENERGY CORPORATION
REPORTED TO ADJUSTED EARNINGS RECONCILIATION
Nine Months Ended September 30, 2018
(Dollars in millions, except per-share amounts)

		Special Items							
	Reported Earnings	**Costs to Achieve Piedmont Merger**	**Regulatory and Legislative Impacts**	**Sale of Retired Plant**	**Impairment Charges**	**Impacts of the Tax Act**	**Discontinued Operations**	**Total Adjustments**	**Adjusted Earnings**
SEGMENT INCOME									
Electric Utilities and Infrastructure	**$ 2,492**	$ —	$ 202 **B**	$ —	$ —	$ 8	$ —	$ 210	$ 2,702
Gas Utilities and Infrastructure	**161**	—	—	—	42 **D**	1	—	43	204
Commercial Renewables	**(4)**	—	—	—	91 **E**	(3)	—	88	84
Total Reportable Segment Income	**2,649**	**—**	**202**	**—**	**133**	**6**	**—**	**341**	**2,990**
Other	**(446)**	41 **A**	—	82 **C**	—	67	—	190	(256)
Discontinued Operations	**(1)**	—	—	—	—	—	1 **G**	1	—
Net Income Attributable to Duke Energy Corporation	**$ 2,202**	**$ 41**	**$ 202**	**$ 82**	**$ 133**	**$ 73 F**	**$ 1**	**$ 532**	**$ 2,734**
EPS ATTRIBUTABLE TO DUKE ENERGY CORPORATION, DILUTED	**$ 3.11**	**$ 0.06**	**$ 0.29**	**$ 0.12**	**$ 0.19**	**$ 0.10**	**$ —**	**$ 0.76**	**$ 3.87**

A — Net of $12 million tax benefit. $53 million recorded within Operating Expenses on the Condensed Consolidated Statements of Operations.

B — Net of $16 million tax benefit at Duke Energy Progress and $47 million tax benefit at Duke Energy Carolinas.

- On the Duke Energy Progress' Condensed Consolidated Statements of Operations, $32 million is recorded within Impairment charges, $31 million within Operations, maintenance and other, $6 million within Interest Expense and $(1) million within Depreciation and amortization.
- On the Duke Energy Carolinas' Condensed Consolidated Statements of Operations, $188 million is recorded within Impairment charges, $8 million within Operations, maintenance and other, and $1 million within Depreciation and amortization.

C — Net of $25 million tax benefit. $107 million recorded within Gains (Losses) on Sales of Other Assets and Other, net on the Condensed Consolidated Statements of Operations.

D — Net of $13 million tax benefit. $55 million recorded within Other Income and Expenses on the Condensed Consolidated Statements of Operations.

E — Net of $2 million Noncontrolling Interests. $93 million goodwill impairment recorded within Impairment charges on the Condensed Consolidated Statement of Operations.

F — $76 million AMT valuation allowance and $3 million tax benefit true up of prior year Tax Act estimates within Income Tax Expense from Continuing Operations on the Condensed Consolidated Statements of Operations.

G — Recorded in Income (Loss) from Discontinued Operations, net of tax on the Condensed Consolidated Statements of Operations.

Weighted Average Shares, Diluted (reported and adjusted) — 706 million

DUKE ENERGY CORPORATION
REPORTED TO ADJUSTED EARNINGS RECONCILIATION
Year Ended December 31, 2018
(Dollars in millions, except per-share amounts)

		Special Items								
	Reported Earnings	**Costs to Achieve Piedmont Merger**	**Regulatory and Legislative Impacts**	**Sale of Retired Plant**	**Impairment Charges**	**Impacts of the Tax Act**	**Severance**	**Discontinued Operations**	**Total Adjustments**	**Adjusted Earnings**
SEGMENT INCOME										
Electric Utilities and Infrastructure	**$ 3,058**	$ —	$ 202 **B**	$ —	$ 46 **D**	$ 24	$ —	$ —	$ 272	$ 3,330
Gas Utilities and Infrastructure	**274**	—	—	—	42 **E**	1	—	—	43	317
Commercial Renewables	**9**	—	—	—	91 **F**	(3)	—	—	88	97
Total Reportable Segment Income	**3,341**	**—**	**202**	**—**	**179**	**22**	**—**	**—**	**403**	**3,744**
Other	**(694)**	65 **A**	—	82 **C**	—	(2)	144 **H**	—	289	(405)
Discontinued Operations	**19**	—	—	—	—	—	—	(19) **I**	(19)	—
Net Income Attributable to Duke Energy Corporation	**$ 2,666**	**$ 65**	**$ 202**	**$ 82**	**$ 179**	**$ 20 G**	**$ 144**	**$ (19)**	**$ 673**	**$ 3,339**
EPS ATTRIBUTABLE TO DUKE ENERGY CORP, DILUTED	**$ 3.76**	**$ 0.09**	**$ 0.29**	**$ 0.12**	**$ 0.25**	**$ 0.03**	**$ 0.21**	**$ (0.03)**	**$ 0.96**	**$ 4.72**

A — Net of $19 million tax benefit. $84 million recorded within Operating Expenses on the Consolidated Statements of Operations.

B — Net of $16 million tax benefit at Duke Energy Progress and $47 million tax benefit at Duke Energy Carolinas.

- On the Duke Energy Progress' Consolidated Statements of Operations, $32 million is recorded within Impairment charges, $31 million within Operations, maintenance and other, $6 million within Interest Expense and $(1) million within Depreciation and amortization.
- On the Duke Energy Carolinas' Consolidated Statements of Operations, $188 million is recorded within Impairment charges, $8 million within Operations, maintenance and other, and $1 million within Depreciation and amortization.

C — Net of $25 million tax benefit. $107 million recorded within Gains (Losses) on Sales of Other Assets and Other, net on the Consolidated Statements of Operations.

D — Net of $14 million tax benefit. $60 million recorded within Impairment Charges on Duke Energy Florida's Consolidated Statements of Operations.

E — Net of $13 million tax benefit. $55 million included within Other Income and Expenses on the Consolidated Statements of Operations.

F — Net of $2 million Noncontrolling Interests. $93 million goodwill impairment recorded within Impairment Charges on the Consolidated Statement of Operations.

G — $20 million true up of prior year Tax Act estimates within Income Tax Expense from Continuing Operations on the Consolidated Statements of Operations.

H — Net of $43 million tax benefit. $187 million recorded within Operations, maintenance and other on the Consolidated Statements of Operations.

I — Recorded in Income (Loss) from Discontinued Operations, net of tax on the Consolidated Statements of Operations.

Weighted Average Shares, Diluted (reported and adjusted) — 708 million

DUKE ENERGY CORPORATION
REPORTED TO ADJUSTED EARNINGS RECONCILIATION
Twelve Months Ended December 31, 2017
(Dollars in millions, except per-share amounts)

		Special Items						
	Reported Earnings	Costs to Achieve Piedmont Merger	Regulatory Settlements	Commercial Renewables Impairments	Impacts of the Tax Act	Discontinued Operations	Total Adjustments	Adjusted Earnings
SEGMENT INCOME								
Electric Utilities and Infrastructure	**$ 3,210**	$ —	$ 98 **B**	$ —	$ (231)	$ —	$ (133)	$ 3,077
Gas Utilities and Infrastructure	**319**	—	—	—	(26) **D**	—	(26)	293
Commercial Renewables	**441**	—	—	74 **C**	(442)	—	(368)	73
Total Reportable Segment Income	**3,970**	**—**	**98**	**74**	**(699)**	**—**	**(527)**	**3,443**
Other	**(905)**	64 **A**	—	—	597	—	661	(244)
Discontinued Operations	**(6)**	—	—	—	—	6 **E**	6	—
Net Income Attributable to Duke Energy Corporation	**$ 3,059**	**$ 64**	**$ 98**	**$ 74**	**$ (102) D**	**$ 6**	**$ 140**	**$ 3,199**
EPS ATTRIBUTABLE TO DUKE ENERGY CORP, DILUTED	**$ 4.36**	**$ 0.09**	**$ 0.14**	**$ 0.11**	**$ (0.14)**	**$ 0.01**	**$ 0.21**	**$ 4.57**

A - Net of $39 million tax benefit. $102 million recorded within Operating Expenses and $1 million recorded within Interest Expense on the Consolidated Statements of Operations.

B - Net of $60 million tax benefit. $154 recorded within Impairment Charges and $4 million recorded within Other Income and Expenses on the Consolidated Statements of Operations.

C - Net of $28 million tax benefit. $92 million recorded within Impairment Charges and $10 million recorded within Other Income and Expenses on the Consolidated Statements of Operations.

D - $118 million benefit recorded within Income Tax Expense from Continuing Operations, offset by $16 million expense recorded within Gas Utilities and Infrastructure's Equity in Earnings of Unconsolidated Affiliates on the Consolidated Statements of Operations.

E - Recorded in (Loss) Income from Discontinued Operations, net of tax on the Consolidated Statements of Operations.

Weighted Average Shares, Diluted (reported and adjusted) - 700 million

DUKE ENERGY CORPORATION
EFFECTIVE TAX RECONCILIATION
September 2019
(Dollars in millions)

	Three Months Ended September 30, 2019		Nine Months Ended September 30, 2019	
	Balance	Effective Tax Rate	Balance	Effective Tax Rate
Reported Income From Continuing Operations Before Income Taxes	$ 1,511		$ 3,388	
Impairment Charge	(25)		(25)	
Noncontrolling Interests	19		110	
Preferred Dividends	(15)		(27)	
Pretax Income Including Noncontrolling Interests and Preferred Dividends and Excluding Special Items	$ 1,490		$ 3,446	
Reported Income Tax Expense From Continuing Operations	$ 188	12.4%	$ 424	12.5%
Impairment Charge	(6)		(6)	
Tax Expense Including Noncontrolling Interests and Preferred Dividends and Excluding Special Items	$ 182	12.2%	$ 418	12.1%

	Three Months Ended September 30, 2018		Nine Months Ended September 30, 2018	
	Balance	Effective Tax Rate	Balance	Effective Tax Rate
Reported Income From Continuing Operations Before Income Taxes	$ 1,230		$ 2,640	
Costs to Achieve Piedmont Merger	16		53	
Regulatory and Legislative Impacts	—		265	
Sale of Retired Plant	—		107	
Impairment of Equity Method Investment	91		146	
Noncontrolling Interests	16		12	
Pretax Income Including Noncontrolling Interests and Excluding Special Items	$ 1,353		$ 3,223	
Reported Income Tax Expense From Continuing Operations	$ 168	13.7%	$ 449	17.0%
Costs to Achieve Piedmont Merger	3		12	
Regulatory and Legislative Impacts	—		63	
Sale of Retired Plant	—		25	
Impairment of Equity Method Investment	—		13	
Impacts of the Tax Act	3		(73)	
Tax Expense Including Noncontrolling Interests and Excluding Special Items	$ 174	12.9%	$ 489	15.2%

Duke Energy Corporation
Available Liquidity Reconciliation
As of September 30, 2019
(In millions)

Cash and Cash Equivalents	$ 379	
Less: Certain Amounts Held in Foreign Jurisdictions	(22)	
Less: Unavailable Domestic Cash	(91)	
	266	
Plus: Remaining Availability under Master Credit Facilities and other facilities	5,897	
Total Available Liquidity (a)	$ 6,163	approximately 6.2 billion

(a) The available liquidity balance presented is a non-GAAP financial measure as it represents Cash and cash equivalents, excluding certain amounts held in foreign jurisdictions and cash otherwise unavailable for operations, and remaining availability under Duke Energy's available credit facilities, including the master credit facility. The most directly comparable GAAP financial measure for available liquidity is Cash and cash equivalents.

Duke Energy Corporation
Operations, Maintenance and Other Expense
(In millions)

	Actual December 31, 2015	Actual December 31, 2016	Actual December 31, 2017	Actual December 31, 2018	Forecast December 31, 2019
Operation, maintenance and other[(a)]	**$5,539**	**$6,223**	**$5,944**	**$6,463**	**$6,035**
Impact of the Adoption of New Accounting Standards[(b)]	103	–	–	–	–
Adjustments:					
Costs to Achieve, Mergers[(c)]	(69)	(238)	(94)	(83)	–
Severance[(c)]	(142)	(92)	–	(187)	–
Litigation Reserve[(c)]	–	–	–	–	–
Ash Basin Settlement and Penalties[(c)]	(14)	–	–	–	–
Regulatory settlement[(c)]	–	–	(5)	(40)	–
Reagents Recoverable[(d)]	(111)	(93)	(90)	(112)	(100)
Energy Efficiency Recoverable[(d)]	(287)	(417)	(485)	(446)	(433)
Other Deferrals and Recoverable[(d)]	(93)	(233)	(246)	(477)	(452)
Margin based O&M for Commercial Businesses	(48)	(185)	(94)	(113)	(213)
Short-term incentive payments (over)/under budget	(19)	(90)	(22)	(30)	–
Non-Rider Recoverable operation, maintenance and other	**$ 4,859**	**$ 4,875**	**$ 4,908**	**$ 4,974**	**$ 4,837**
YoY change	*3%*	*0%*	*1%*	*1%*	*-3%*

(a) As reported in the Consolidated Statements of Operations.
(b) Beginning January 1, 2018, Duke Energy adopted new accounting guidance for the presentation of net periodic costs related to benefit plans. Prior to this guidance, Duke Energy presented the total non-capitalized net periodic costs within Operation, maintenance and other expense. Retrospective application of this guidance required Duke Energy to reclassify the presentation of non-service cost (benefit) components of net periodic costs to Other income and expenses. In accordance with the transition guidance for the new accounting rules, Operations, maintenance and other expense has been recast for the years ended December 31, 2017 and 2016 and periods prior to January 1, 2016 have not required recasting. This adjustment reflects the historical impact of adopting the new accounting standard to the earliest periods presented (December 31, 2015).
(c) Presented as a special item for the purpose of calculating adjusted earnings and adjusted diluted earnings per share.
(d) Primarily represents expenses to be deferred or recovered through rate riders.

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen / Richard A. Baudino / Glenn Watkins

QUESTION No. 8
Page 1 of 1

> Please provide copies of any and all documents not created by Messrs. Watkins, Kollen, and Baudino, including but not limited to, analysis, summaries, cases, reports, evaluations, *etc*., that Messrs. Watkins, Kollen, and Baudino relied upon, referred to, or used in the development of their testimony.

RESPONSE:

Refer to the response to Question 7. To the extent Mr. Kollen or Mr. Baudino relied on other documents, they are cited in their respective testimonies and have been provided or are otherwise publicly available, except to the extent certain documents may be confidential and/or subject to copyright restrictions.

In addition to the Company's filing and responses to data requests, Mr. Watkins relied upon certain publications documented and footnoted in his direct testimony that are copyrighted and are either available on the internet or in the possession of virtually every public utility regulatory expert and are therefore, not provided.

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen / Richard A. Baudino / Glenn Watkins / Counsel as to objection

QUESTION No. 9
Page 1 of 1

> Please provide copies of any and all presentations made by Messrs. Watkins, Kollen or Baudino within the last three years involving or relating to the following: 1) utility rate-making; 2) rate of return; 3) rider cost recovery; 4) depreciation; 5) taxes; 6) vegetation management; 7) costs of participating in PJM, including Regional Transmission Expansion Plan (RTEP) expenses; 8) utility generation outage maintenance expenses; and 9) sharing of off-system sales revenues between utilities and customers.

RESPONSE:

Mr. Kollen did not make any presentations outside the submission of his testimonies listed in Exhibit___(LK-1).

Mr. Baudino did not make any presentations outside the submission of his testimonies listed in Exhibit___(RAB-1).

As part of his consulting practice, Mr. Watkins routinely advises clients for educational and other purposes on the topics discussed in the request. Mr. Watkins does not maintain records of informal presentations or advice given to clients on these matters. However, Mr. Watkins' has made formal presentations during the last three years to the following entities:

> May 4, 2017 – Presentation to Virginia Energy Purchasing Governmental Association ("VEPGA") – a confidential presentation made to the members of VEPGA concerning their negotiated contract rates from Dominion Energy. Objection. Given the confidential nature of this topic, Mr. Watkins' presentation is not provided.

> April 4, 2018 – Presentation to National Association of State Utility Consumer Advocates ("NASUCA") – PowerPoint presentation attached.

> June 2019 – Presentation to NASUCA – PowerPoint presentation attached.

WITNESS/RESPONDENT RESPONSIBLE:
Richard A. Baudino

QUESTION No. 10

a) Please identify each rate case for an investor-owned regulated electric utility, natural gas utility or combination electric and natural gas utility, in which Mr. Baudino has testified in the last five years.

b) Please provide Mr. Baudino's recommended return on equity for each rate case identified in part (a).

c) Please provide the prevailing yield on long-term Treasury bonds at the time Mr. Baudino submitted his recommended return on equity for each rate case identified in part (a).

RESPONSE:

(a)-(c) Refer to the response to Questions 6 and 7.

WITNESS/RESPONDENT RESPONSIBLE:
Richard A. Baudino

QUESTION No. 11
Page 1 of 1

a) Please provide a copy of all articles, documents, textbooks (or relevant portions of such documents) cited in Mr. Baudino's testimony and footnotes.

b) Please provide a hard copy of the Edison Electric Institute document cited on line 13, page 13 and line 5, page 14 of Mr. Baudino's testimony. Please provide the most recent editions of this document.

RESPONSE:

a) Refer to Mr. Baudino's response to Question No. 7

b) Refer to Mr. Baudino's response to Question No. 7. More recent editions of this document, if available, may be found on EEI's web site.

WITNESS/RESPONDENT RESPONSIBLE:
Richard A. Baudino

QUESTION No. 12
Page 1 of 1

Please provide the currently authorized return on equity for the each of the utilities in Mr. Baudino's peer group of utility companies.

RESPONSE:

Mr. Baudino did not compile a list of the currently authorized return on equity for each of the utilities in his proxy group as part of his work in this case. The Value Line Investment Survey reports for each company show the recently authorized returns on equity for each company.

WITNESS/RESPONDENT RESPONSIBLE:
Richard A. Baudino

QUESTION No. 13
Page 1 of 1

> Provide all work papers and supporting documentation, including spreadsheets with cells intact, used and relied upon by Mr. Baudino in the preparation of his Direct Testimony and exhibits, which have not already been provided.

RESPONSE:

Refer to the response to Question 7.

WITNESS/RESPONDENT RESPONSIBLE:
Richard A. Baudino

QUESTION No. 14
Page 1 of 1

> Provide Excel spreadsheet versions of Mr. Baudino's exhibits with cell formulas intact.

RESPONSE:

Refer to the response to Question 7.

WITNESS/RESPONDENT RESPONSIBLE:
Richard A. Baudino

QUESTION No. 15
Page 1 of 1

> On page 21, lines 15-16, Mr. Baudino adjusts the dividend yield by (1+ 0.5g). Please provide any reference to any college-level corporate finance textbook that relies on such a model. Does the classic Brealey, Myers, Allen textbook rely on this approach in performing the DCF model? Does the Duff & Phelps Valuation Yearbook cited by Mr. Baudino on lines 3-4 of Page 27 rely on such an adjustment?

RESPONSE:

Mr. Baudino does not know of a reference to a college-level corporate finance textbook that shows the 1 + 0.5g method to calculate the expected dividend yield, including Brealey, Myers, Allen. Duff & Phelps uses the Capital Asset Pricing Model to estimate the cost of capital, not the discounted cash flow model.

WITNESS/RESPONDENT RESPONSIBLE:
Richard A. Baudino

QUESTION No. 16
Page 1 of 1

> On page 2 of Exhibit RAB-4, Mr. Baudino reports the results of his DCF analyses in summary form only. Please provide in Excel readable format the DCF results for each company in his peer group using the various growth proxies.

RESPONSE:

Mr. Baudino did not perform this calculation as part of his work in this case. The Company may, if it wishes, perform this calculation using Mr. Baudino's spreadsheet provided in response to Question No. 7.

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen

QUESTION No. 17
Page 1 of 1

> In Case No. 2015-00343, Mr. Kollen provided testimony objecting to Atmos Energy's proposal to include in rate base its regulatory asset for rate case expense. Please confirm that the settlement approved by the Commission in that proceeding did not exclude this regulatory asset.

RESPONSE:

The settlement in Case No. 2015-00343 reflected a base rate increase of $500,000. The settlement did not specifically address the treatment of rate case expense.

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen

QUESTION No. 18
Page 1 of 1

> In Case No. 2018-00281, Mr. Kollen provided testimony on behalf of the Attorney General recommending adjustments to Atmos Energy's proposed revenue requirement. Does Mr. Kollen agree that (1) he made no recommendation to eliminate Atmos Energy's proposed addition of the rate expense regulatory asset from rate base and (2) the approved rate base in that proceeding included the regulatory asset for rate case expense.

RESPONSE:

Yes.

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen

QUESTION No. 19
Page 1 of 1

> Please provide a reference in the Kentucky Administrative Regulations that limits how frequently a utility should update its depreciation studies.

RESPONSE:

Mr. Kollen has not reviewed the Kentucky Administrative Regulations to make such an investigation and is not aware of whether such a reference exists or does not exist.

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen

QUESTION No. 20
Page 1 of 1

Please provide previous cases where the Kentucky Public Service Commission has deemed it imprudent to perform a new depreciation study as part of a base rate case.

a. Please state if Mr. Kollen is aware of the Kentucky Public Service Commission ever opining on the frequency of depreciation studies performed by utilities in base rate proceedings?

b. If the response is in the affirmative, please provide citations to all such orders/opinions.

RESPONSE:

Mr. Kollen has not researched this issue and does not know whether the Commission has ever opined on the frequency of depreciation studies performed by utilities in base rate proceedings.

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen

QUESTION No. 21
Page 1 of 1

> Refer to Page 62 of Mr. Kollen's testimony. Please provide the detailed calculations that support Mr. Kollen's claim that the future revenue requirement for the battery storage project will be approximately $1.384 million.

RESPONSE:

The Company's quantification of the battery storage project was based on costs being added at the end of December 2020, so only 3 months of costs were included in the filing. (See a copy of the calculation provided as Exhibit___(LK-32)) The $1.384 million is that number of $0.346 million multiplied by 4 to annualize the effects that would be included in a future proceeding.

EXHIBIT ____ (LK-32)

Duke Energy Kentucky
Case No. 2019-00271
Staff's Second Set Data Requests
Date Received: October 11, 2019

STAFF-DR-02-086

REQUEST:

Refer to the Lawler Testimony, page 16, lines 9-11. Provide the calculation of the revenue requirement impact of Duke Kentucky's proposed battery storage project.

RESPONSE:

See Staff-DR-02-086 Attachment.

PERSON RESPONSIBLE: Sarah E. Lawler

Duke Energy Kentucky
Estimated Revenue Requirement
Battery Storage Project

Line	Description	Test Period
1	Gross Plant[a]	$2,508,971
2	Accum Depreciation [b]	(83,632)
3	Net Plant in Service	$2,425,339
4	Accum Def Income Taxes on Plant [b]	($8,781)
5	Rate Base	**$2,416,558**
6	Return on Rate Base (Pre-Tax %) [c]	8.96%
7	Return on Rate Base (Pre-Tax)	$216,451
8	Depreciation Expense	83,632
9	Annualized Property Tax Expense [d]	46,081
10	Revenue Requirement (Lines 7 - 9)	$346,165

Assumptions:

[a] Schedule B-2.1 Page 10 of 12, Line 6

[b] Assumes 15 year book life; 15 year MACRS

[c] Weighted-Average Cost of Capital from Schedule A in Case No. 2019-00271, with ROE at 9.8%, grossed up for 21% FIT rate.

[d] Assumes 1.9% of net plant.

Duke Energy Kentucky
Estimated Revenue Requirement
Battery Storage Project

Line	Description	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21
		Test Period												
1	Placed in Service	-	-	-	-	-	-	-	-	-	8,154,156	-	-	-
2	Culmative Plant In Service	-	-	-	-	-	-	-	-	-	8,154,156	8,154,156	8,154,156	8,154,156
3	13 Month Average (Average of Ln 2):	2,508,971												

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen

QUESTION No. 22
Page 1 of 1

> Please provide the detailed calculations that support your claim that the annual credit associated with the battery storage project in RIDER PSM will be $0.637 million.

RESPONSE:

The $0.637 million amount is the net of the $0.800 million (Direct Testimony of Kuznar at 7-8) in estimated annual revenues from the project less the $0.163 million (Direct Testimony of Lawler at 15) in ongoing O&M expenses.

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen

QUESTION No. 23
Page 1 of 1

Please confirm that Mr. Kollen's proposed adjustment to remove $346k in the revenue requirement related to the EV pilot and the battery storage pilot was calculated using 9.8% ROE as filed by the Company in its Application.

(a) If yes, does Mr. Kollen agree that his adjustment to remove the battery storage and EV pilot should be $317,528 and $135,447 respectively if using his recommended 9.0% ROE?
(b) Does Mr. Kollen agree that his adjustment to remove the battery storage and EV pilot, if adopted by the Commission, should be calculated with the final ROE approved by the Commission.
(c) If no, please explain why?

RESPONSE:

Yes. Mr. Kollen's proposed adjustments removed the totality of the revenue requirement amounts included by the Company in its filing utilizing the Company's requested ROE.

a. No. The sequence of Mr. Kollen's adjustments matters. He quantified the effect of the 9.0% return on equity after the rate base adjustments, including the removal of the costs of these pilot programs from rate base.
b. No. The sequence of the Commission's adjustments matters. If the Commission first removes the battery storage and EV pilot costs from rate base, in the same sequence as Mr. Kollen's adjustments, then the effect on the revenue requirement should be calculated using the 9.8% return on equity because that is what the Company included in the revenue requirement.
c. Refer to the response to part (b) of this question.

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen

QUESTION No. 24
Page 1 of 1

> Please refer to Mr. Kollen's discussion of depreciation rates unit life spans for combustion turbine units on pp. 55-56 of his testimony. Does he agree that the units referenced have either undergone, or are likely to undergo, major overhauls during the overall period of their service?

RESPONSE:

Yes. To the extent the units have undergone major overhauls, then the capitalized costs are included in plant and subject to depreciation. To the extent that the units will undergo major overhauls in the future, then the capitalized costs will be included in plant and subject to depreciation after those costs have been incurred.

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen

QUESTION No. 25
Page 1 of 1

Is Mr. Kollen a Certified Depreciation Professional?

RESPONSE:

No. Mr. Kollen is a Certified Public Accountant, Certified Management Accountant, and Chartered Global Management Accountant. Mr. Kollen also is a member of the Society of Depreciation Professionals and several other professional organizations.

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen

QUESTION No. 26
Page 1 of 1

Has Mr. Kollen ever performed a power plant decommissioning study?

RESPONSE:

No. The utility typically performs or retains a consultant to perform such studies in support of a request for ratemaking recovery of these unknown and uncertain future costs. This approach is unique to the regulated utility industry, except for certain legal liabilities. Under GAAP, other companies are not allowed to accrue unknown and uncertain future costs for decommissioning as a component of depreciation expense, except for certain legal liabilities. In utility rate proceedings, Mr. Kollen reviews the utility's request and the study that it or a consultant developed for that purpose and then makes appropriate recommendations for ratemaking and accounting purposes.

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen

QUESTION No. 27
Page 1 of 1

Has Mr. Kollen ever bid on or worked on the decommissioning of a power plant?

RESPONSE:

No. Refer to the response to Question 26.

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen

QUESTION No. 28
Page 1 of 1

For each combustion turbine plant referenced on page 55 of Mr. Kollen's testimony, please provide the following:

The year placed in service;
(a) The fuel type;
(b) The MW capacity;
(c) The type of combustion turbine technology (e.g., frame, reciprocating engine, etc.);
(d) Any known major capital expenditures since the plant was placed in service; and,
(e) If Mr. Kollen is not aware of any of this information for any of the plants listed on page 55 of his testimony, or if he did not consider any of this information when making his recommendations, please state so.

RESPONSE:

See table below with information from EIA Form 860. The type of CT technology or known major capital expenditures are not listed in the EIA Form 860 survey data. In his testimony, Mr. Kollen referenced the DEF PL Bartow Units 1 and 2. The reference should have been to Units 2 and 4 as shown on the table below.

Utility	Unit	Operating Year	Fuel Type	Nameplate Capacity
Duke Energy Florida, LLC	Avon Park	1968	Natural Gas	33.7
Duke Energy Florida, LLC	Higgins Unit 1	1969	Natural Gas	33.7
Duke Energy Florida, LLC	Higgins Unit 2	1969	Natural Gas	33.7
Duke Energy Florida, LLC	Higgins Unit 3	1970	Natural Gas	42.9
Duke Energy Florida, LLC	Higgins Unit 4	1971	Natural Gas	42.9
Duke Energy Florida, LLC	PL Bartow Unit 2	1972	Natural Gas	55.4
Duke Energy Florida, LLC	PL Bartow Unit 4	1972	Natural Gas	55.4
Kentucky Utilities Company	Haefling Unit 1	1970	Natural Gas	20.7
Kentucky Utilities Company	Haefling Unit 2	1970	Natural Gas	20.7
Louisville Gas & Electric Company	Cane Run Unit 11	1968	Natural Gas	16.3
Louisville Gas & Electric Company	Paddy's Run Unit 11	1968	Natural Gas	16
Louisville Gas & Electric Company	Paddy's Run Unit 12	1968	Natural Gas	32.6
Louisville Gas & Electric Company	Zorn Unit 1	1969	Natural Gas	18
Southern Indiana Gas and Elect. Comp.	Northeast Unit 1	1963	Natural Gas	10.7
Southern Indiana Gas and Elect. Comp.	Northeast Unit 2	1964	Natural Gas	11.5

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen

QUESTION No. 29
Page 1 of 1

Please list all Duke Energy Kentucky programs currently approved by the KY PSC which are not strictly "necessary for the provision of electric service."

RESPONSE:

Mr. Kollen has not performed such a study.

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen

QUESTION No. 30
Page 1 of 1

> What evidence leads Mr. Kollen to believe that the Electric Vehicle Pilot will be managed by another Duke Energy affiliate and not Duke Energy Kentucky?

RESPONSE:

Refer to the Direct Testimony of Lang Reynolds at pages 1–2.

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen

QUESTION No. 31
Page 1 of 1

> Please describe the extent to which, if any, Mr. Kollen's proposed adjustment to rate base for Accounts Payable Related to Fuel overlaps with the proposal he characterizes as an "alternative adjustment" for Customer Financing of Materials and Suppliers Inventories. Assuming the Accounts Payable Related to Fuel is included in the Materials and Supplies Inventories, does Mr. Kollen agree that he is double counting at least part of his adjustment?

RESPONSE:

Mr. Kollen is not aware of an overlap between the Accounts Payable Related to Fuel and the Accounts Payable Related to Materials and Supplies Inventory. The second question above contains a faulty premise. The Accounts Payable Related to Fuel is associated with the Fuel Inventories and not the Materials and Supplies Inventories.

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen

QUESTION No. 32
Page 1 of 1

Does Mr. Kollen agree that deferred income taxes can only exist if there is a difference in book and taxable income?

RESPONSE:

Deferred income taxes exist only if there is a temporary difference, according to GAAP.

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen

QUESTION No. 33
Page 1 of 1

Does Mr. Kollen agree that there can be no deferred incomes taxes if a company is not allowed to earn a net income?

RESPONSE:

No. This is an incorrect premise. There are deferred income taxes whenever there are temporary differences regardless of whether a company is allowed to earn an equity or any other return.

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen

QUESTION No. 34
Page 1 of 1

> Assuming the Commission adopts Mr. Kollen's proposal that Duke Energy Kentucky is only allowed to charge customers for a return at the Money Pool short-term interest rate, would Mr. Kollen agree that the implication is that Duke Energy Kentucky's customers are not responsible for Duke Energy Business Services' net income?

RESPONSE:

Under Mr. Kollen's recommendation, there would be no equity return and no income tax gross-up on the equity return applied to certain DEBS assets. However, DEBS still would have ADIT due to temporary differences.

WITNESS/RESPONDENT RESPONSIBLE:
Lane Kollen

QUESTION No. 35
Page 1 of 1

> Explain why Mr. Kollen believes it is appropriate to refund any deferred income taxes to Duke Energy Kentucky's customers when he simultaneously is arguing that Duke Energy Kentucky's customers are not responsible for any of the income for Duke Energy Business Services that would generate deferred income taxes.

RESPONSE:

The question reflects a false dichotomy. The DEBS ADIT was the accumulated income tax effect of temporary differences in prior years, not the result of DEBS net income in those prior years. The DEBS EDIT was simply the result of the reduction in the federal income tax rate applied to those temporary differences.

WITNESS/RESPONDENT RESPONSIBLE:
Glenn Watkins

QUESTION No. 36
Page 1 of 1

> Refer to the Commission's April 13, 2018 Order, pages 44-45, in Case No. 2017-00321 approving Duke Energy Kentucky current base rates where the Commission found that "Duke Kentucky's revised 12-CP COSS supports a residential customer charge in the amount of $11.31, which includes all costs identified as customer-related in its Case No. 2017-00321 COSS. This method of calculating the customer charge is generally accepted in the utility industry and is being accepted by the Commission."
>
> (a) Is Mr. Watkins suggesting that the COSS methodology approved by the Commission in Case No. 2017-00321 differs from the COSS methodology being proposed in this instant case?
>
> (b) If the answer to (a) is yes, please provide a detailed summary of all differences noted by Mr. Watkins impacting the calculation of the residential customer charge.

RESPONSE:

(a) No. Please also refer to Mr. Watkins' direct testimony, page 13, line 1 through page 14, line 4.

(b) See response to (a).

WITNESS/RESPONDENT RESPONSIBLE:
Glenn Watkins

QUESTION No. 37
Page 1 of 1

> AG witness Watkins states on page 8 lines 7 and 8 of his testimony that "competitive market-based prices are generally structured based on usage, *i.e.* volume-based pricing." Please provide any research or studies that supports this statement.

RESPONSE:

This is common knowledge to the common man wherein no research or studies are required or have been conducted.

WITNESS/RESPONDENT RESPONSIBLE:
Glenn Watkins

QUESTION No. 38
Page 1 of 1

> Mr. Watkins states, on page 10, lines 19 and 20 of his testimony that "users requiring more of the Company's products and services should pay more than customers who use less of these products and services." Under the company's proposed rates, do users who use more of the Company's products and services pay more than customers who use less of these products and services?

RESPONSE:

Yes.

WITNESS/RESPONDENT RESPONSIBLE:
Glenn Watkins

QUESTION No. 39
Page 1 of 1

Mr. Watkins states, on page 12, lines 19 and 20, that "Consumers and the market have a clear preference for volumetric pricing."

(a) Please provide any research or studies that support this statement.
(b) Has he performed any surveys of Duke Energy Kentucky customers on their desire for volumetric pricing?
(c) If answer to (b) is in the affirmative, please provide.

RESPONSE:

(a) See response to 37.

(b) No.

(c) See response to (b).

WITNESS/RESPONDENT RESPONSIBLE:
Glenn Watkins

QUESTION No. 40
Page 1 of 1

> Does Mr. Watkins believe that the Company's proposed Rate RS is a Straight Fixed Variable rate design?

RESPONSE:

No. However, Mr. Watkins' discussion of FERC's implementation of Straight Fixed Variable pricing as a method to <u>maximize</u> (increase) consumption should not be taken out of context. Rather, Mr. Watkins' discussion of Straight Fixed Variable pricing unequivocally shows that higher fixed charges promote the additional consumption of public utility products and services. Mr. Watkins does not imply that Duke is proposing a true Straight Fixed Variable pricing structure, but rather, provides authoritative support that a policy to increase fixed charges (relative to volumetric charges) promotes additional consumption and is contrary to conservation efforts.

WITNESS/RESPONDENT RESPONSIBLE:
Glenn Watkins

QUESTION No. 41
Page 1 of 1

> Mr. Watkins states on page 9 lines 22 through 25 that "Fair and equitable pricing of a regulated monopoly's products and services should reflect the benefits received for the goods and services. In this regard, it is generally agreed in our society, and economic system, that those who receive more benefits should pay more in total than those who receive fewer benefits." Please provide the basis for the statement.

RESPONSE:

Mr. Watkins' statement is self-explanatory and needs no further support.

WITNESS/RESPONDENT RESPONSIBLE:
Glenn Watkins

QUESTION No. 42
Page 1 of 1

> Mr. Watkins states on page 5 lines 4 through 6 that "…if an additional customer is added to the distribution system, the Company will not incur additional conductor investment costs in order to serve this new customer." Please provide the basis and any empirical evidence for the statement.

RESPONSE:

When Duke adds a new secondary voltage customer connection, a new meter and service line will be required as well as possibly an additional transformer. However, the Company will not reconfigure its distribution system by adding new distribution conductors to accommodate this incremental customer's load. This is common knowledge in the industry and is based on Mr. Watkins' experience as an electricity consumer and regulatory expert for over 39 years. Please note Mr. Watkins does acknowledge that if a very large commercial or industrial customer is added, some modifications to the Company's distribution system may be required. Mr. Watkins' discussion is meant to relate to new residential customers.

WITNESS/RESPONDENT RESPONSIBLE:
Glenn Watkins

QUESTION No. 43
Page 1 of 1

> Has Mr. Watkins performed any study or analysis comparing Duke Energy Kentucky's current and/or proposed electric residential customer charge to that of other electric utilities regulated by the Commission? If the answer is in the affirmative, please provide such studies.

RESPONSE:

Not for purposes of this case. However, Mr. Watkins is generally familiar with the Commission-approved residential customer charges for investor-owned electric utilities within the State.

WITNESS/RESPONDENT RESPONSIBLE:
Glenn Watkins / Counsel as to Objection

QUESTION No. 44
Page 1 of 1

> Has Mr. Watkins or the Kentucky AG performed any study or analysis comparing Duke Energy Kentucky's current and/or proposed electric residential customer charge to that of other electric utilities in the country. If the answer is in the affirmative, please provide such studies.

RESPONSE:

Objection. The Attorney General is not testifying in this proceeding. Mr. Watkins responds: No. However, Mr. Watkins' practices throughout the Country and as indicated on page 13 of his direct testimony, the policy of establishing residential customer charges varies across commissions in this Country.

WITNESS/RESPONDENT RESPONSIBLE:
Glenn Watkins

QUESTION No. 45
Page 1 of 1

> Is Mr. Watkins aware of the Kentucky Public Service Commission ever approving the direct customer cost analysis methodology discussed on pages 15 and 16 of his testimony? If the answer is in the affirmative, please provide citations to such orders.

RESPONSE:

Mr. Watkins is not aware of this Commission either accepting or rejecting a direct customer cost analysis.

WITNESS/RESPONDENT RESPONSIBLE:
Glenn Watkins

QUESTION No. 46
Page 1 of 1

> Is Mr. Watkins aware of the Kentucky Public Service Commission ever excluding all costs associated with conductors and poles from the fixed costs included in a customer charge calculation. If the answer is in the affirmative, please provide citations to commission orders excluding all such costs.

RESPONSE:

Mr. Watkins is not aware of this Commission either accepting or rejecting the exclusion of costs associated with conductors and poles in determining an appropriate customer charge.

WITNESS/RESPONDENT RESPONSIBLE:
Glenn Watkins

QUESTION No. 47
Page 1 of 1

> Refer to page 3, lines 9-10 of Mr. Watkins' testimony, where he opines that low income customers would incur very large percentage increases in their total electric bills. Please provide the information, including any workpapers, relied upon to support his opinion.

RESPONSE:

This question does not accurately reflect Mr. Watkins' testimony. Rather, Mr. Watkins' testimony on page 3, lines 9–10 states: "However, low energy usage customers including those that are low income customers would incur very large percentage increases in their total electric bills."

Mr. Watkins' statement is a matter of arithmetic given the Company's proposed 27.3% in the fixed residential monthly customer charge.

WITNESS/RESPONDENT RESPONSIBLE:
Glenn Watkins

QUESTION No. 48
Page 1 of 1

> Refer to page 9, lines 25-28 of Mr. Watkins' testimony, where he opines that kilowatt hour (kWh) usage is the best indicator of benefits received by a customer. Please provide the information, including any documents, upon which he relied upon to support that opinion.

RESPONSE:

Electricity consumers are customers of an electric utility in order to enable them to purchase and use the energy provided by electricity. The amount of electricity consumed and purchased provides what is known in economic terms as "utility" as it is a measurement of the usefulness and benefits a consumer receives. Electricity energy consumption is measured in kWh. Therefore, the level of kWh consumption is the best indicator of the benefits (utility) received by an electricity consumer.

WITNESS/RESPONDENT RESPONSIBLE:
Glenn Watkins

QUESTION No. 49
Page 1 of 1

> Please state whether Mr. Watkins has ever opined in a different proceeding that electric pricing should not reflect the utility's long-term costs, wherein all costs are variable or volumetric in nature.

RESPONSE:

Not that he can recall. However, Mr. Watkins' routinely evaluates negotiated (discounted) rates for certain customers (generally interruptible) wherein these rates are based on short-run incremental (primarily variable) costs.