2.2. Fort Wayne Streetlighting Billing/Audit issues: I&M and the City will resolve the discrepancies among I&M's tariff, billing data, and ledger, and the City's streetlight inventory by using the Collector app data. Specifically, the parties will meet within 60 days after issuance of a Commission Order approving this Settlement Agreement to resolve these discrepancies. This data should include, by map section, the light type, size in watts, GPS location, physical location and any other attributes contained in the Collector app. I&M's monthly billing will reflect the agreed upon number of streetlights and sizes owned by the City served by I&M on or before August 31, 2024. Monthly inventory updates, if applicable, will be sent to I&M to maintain billing accuracy, and I&M will implement such updates in a timely manner to be included in the next monthly billing cycle as reasonable. Because the number of streetlights may change periodically throughout a given year, the parties will commit to meet in February and August each year to discuss any changes or issues identified. If either party requests an audit, both parties will conduct an audit together, as needed, in a timely manner, to verify sections of the streetlights owned by the City. I&M will revise and streamline the Fort Wayne Street Lighting tariff attached hereto as Settlement Agreement Attachment D. The City understands and acknowledges that automating the integration of the Collector app data with I&M's legacy Customer Information System (CIS) would be cost-prohibitive. However, within six months of a Final Order approving this Settlement Agreement, I&M will arrange a meeting between the City and I&M's CIS team, which will be sufficiently in advance of the "go live" date of the new CIS system to allow the parties a meaningful opportunity to explore the feasibility and cost estimates for automating the integration of the Collector app data with the new CIS system. The parties agree to consider all cyber security and data security concerns.

3. Grandfathering Current LGS Customers. I&M agrees to revise the proposed eligibility language for Tariff LGS to grandfather existing customers under the current eligibility requirements of an annual maximum demand of 60 kW or greater. The proposed Availability of Service for Tariff L.G.S. would read as follows:

> Available for general service customers. Customers may continue to qualify for service under this tariff until their 12-month average metered demand exceeds 1,000 kW. Customers requesting service under Tariff L.G.S. on and after [insert date of Cause No. 45933 Order] must have a 12-month average metered demand of 60 kW or greater. Customers that qualified for Tariff L.G.S. prior to [insert date of Cause No. 45933 Order] may remain on Tariff L.G.S. until their 12-month average metered demand exceeds 1,000 kW or they elect to leave Tariff L.G.S.

4. Tariff IP. The Tariff IP kVAr credit proposed by IG witness Dauphinais will be implemented as agreed to and modified by, the rebuttal testimony of I&M witness Fischer.

5. Residential Service.

5.1. Monthly Fixed Charge. The Settling Parties agree that I&M's standard residential tariff service charge will be $15.00 per month. The Settling Parties agree the monthly service charge for Rate RS-TOD and Rate RS-TOD2 will be $15.00 per month.

5.2. Multi-Family Rate Proposal. Following full deployment of AMI, I&M will collect data for one year and analyze cost differentials between single- and multi-family residential customers. I&M will solicit input from the CAC and other interested Settling Parties on sample size for the data collection and the scope of analysis. The cost of the supporting analysis will be limited to no more than $50,000, excluding internal labor. I&M will consider a new multi-family rate for qualifying residential customers in its next basic rate case filing following the completion of this analysis. In advance of such rate case filing, I&M will offer to meet with CAC and other interested Settling Parties to discuss a potential multi-family rate and will also provide CAC and any other interested Settling Party with the results of the Company's analysis.

5.3. Residential LIHEAP Customer Late Payment Charge. I&M agrees that, once in each half calendar year, at the request of the customer who received LIHEAP assistance within the last twelve months, the Company will waive the late payment charge on a delinquent bill, provided payment is tendered not later than the last date for payment of net amount of the next succeeding month's bill.

5.4. Residential Service Disconnections. With respect to disconnections for non-payment, I&M agrees not to disconnect service for any residential customer on Fridays, Saturdays, Sundays and Holidays (New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Friday after Thanksgiving Day, December 24, and Christmas Day).

6. Contribution. I&M agrees to provide Indiana Community Action Association with $200,000 in both 2024 and 2025 to assist low income customers. I&M's revenue deficiency in this Cause will not be adjusted to include the incremental costs of this contribution.

7. Remaining Issues.

7.1. Solely as a matter of compromise, the Settling Parties agree that the new basic rates approved by the Commission will be implemented by the Company on a service rendered basis on or after the date the Commission approves the new tariff following the Company's compliance filing in this proceeding.

7.2. Any matters not addressed by this Settlement Agreement will be adopted as proposed by I&M in its direct and rebuttal case.

7.3. The Settling Parties agree to work cooperatively on news releases and/or other announcements to the public about this Settlement Agreement.

II. PRESENTATION OF THE SETTLEMENT AGREEMENT TO THE COMMISSION.

A. The Settling Parties shall support this Settlement Agreement before the Commission and request that the Commission expeditiously accept and approve the Settlement Agreement.

B. The Settling Parties may file testimony specifically supporting the Settlement Agreement. The Settling Parties agree to provide each other with an opportunity to review drafts of testimony supporting the Settlement Agreement and to consider the input of the other Settling Parties. Such evidence, together with the evidence previously prefiled in this Cause will be offered into evidence without objection and the Settling Parties hereby waive cross-examination of each other's witnesses. The Settling Parties propose to submit this Settlement Agreement and related evidence conditionally, and if the Commission fails to approve this Settlement Agreement in its entirety without any change or condition(s) unacceptable to any Settling Party, the Settlement and supporting evidence shall be withdrawn, and the Commission will continue to hear this Cause with the proceedings resuming at the point they were suspended by the filing of this Settlement Agreement.

C. A Commission Order approving this Settlement Agreement shall be effective immediately, and the agreements contained herein shall be unconditional, effective and binding on all Settling Parties as an Order of the Commission.

III. EFFECT AND USE OF SETTLEMENT AGREEMENT.

A. It is understood that this Settlement Agreement is reflective of a negotiated settlement and neither the making of this Settlement Agreement nor any of its provisions shall constitute an admission by any Settling Party in this or any other litigation or proceeding except to the extent necessary to implement and enforce its terms. It is also understood that each and every term of this Settlement Agreement is in consideration and support of each and every other term.

B. Neither the making of this Settlement Agreement (nor the execution of any of the other documents or pleadings required to effectuate the provisions of this Settlement Agreement), nor the provisions thereof, nor the entry by the Commission of a Final Order approving this Settlement Agreement, shall establish any principles or legal precedent applicable to Commission proceedings other than those resolved herein.

C. This Settlement Agreement shall not constitute and shall not be used as precedent by any person or entity in any other proceeding or for any other purpose, except to the extent necessary to implement or enforce this Settlement Agreement.

D. This Settlement Agreement is solely the result of compromise in the settlement process and except as provided herein, is without prejudice to and shall not constitute a waiver of any position that any Settling Party may take with respect to any or all of the items resolved here and in any future regulatory or other proceedings.

E. The Settling Parties agree the evidence in support of this Settlement Agreement constitutes substantial evidence sufficient to support this Settlement Agreement and provides an adequate evidentiary basis upon which the Commission can make any findings of fact and conclusions of law necessary for the approval of this Settlement Agreement, as filed. The Settling Parties shall prepare and file an agreed proposed order with the Commission as soon as reasonably possible after the filing of this Settlement Agreement and the final evidentiary hearing.

F. The communications and discussions during the negotiations and conferences and any materials produced and exchanged concerning this Settlement Agreement all relate to offers of settlement and shall be confidential, without prejudice to the position of any Settling Party, and are not to be used in any manner in connection with any other proceeding or otherwise.

G. The undersigned Settling Parties have represented and agreed that they are fully authorized to execute the Settlement Agreement on behalf of their respective clients, and their successor and assigns, which will be bound thereby.

H. The Settling Parties shall not appeal or seek rehearing, reconsideration or a stay of the Commission Order approving this Settlement Agreement in its entirety and without change or condition(s) unacceptable to any Settling Party (or related orders to the extent such orders are specifically implementing the provisions of this Settlement Agreement).

I. The provisions of this Settlement Agreement shall be enforceable by any Settling Party upon approval and incorporation into a Final Order first before the Commission and thereafter in any state court of competent jurisdiction as necessary.

J. This Settlement Agreement may be executed in two or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

ACCEPTED AND AGREED AS OF THE 20TH DAY OF DECEMBER, 2023.

INDIANA MICHIGAN POWER COMPANY

Steven F. Baker
I&M President and Chief Operating Officer
Indiana Michigan Power Center
Fort Wayne, Indiana 46802

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

Lorraine Hitz
Carol Sparks Drake
Office of Utility Consumer Counselor
115 West Washington Street, Suite 1500 South
Indianapolis, Indiana 46204

I&M INDUSTRIAL GROUP

Joseph P. Rompala
Anne E. Becker
Emily R. Vlasak
LEWIS & KAPPES, P.C.
One American Square, Suite 2500
Indianapolis, Indiana 46282-0003

CITIZENS ACTION COALITION OF INDIANA, INC.

Kerwin L. Olson
Citizens Action Coalition of Indiana, Inc.
1915 West 18th Street, Suite C
Indianapolis, Indiana 46202

CITY OF FORT WAYNE, INDIANA

Kevin D. Koons

Brian C. Bosma
Kevin D. Koons
Kroger Gardis & Regas, LLP
111 Monument Circle Drive, Suite 900
Indianapolis, IN 46204-5125

CITY OF MARION, INDIANA, and MARION MUNICIPAL UTILITIES

Kristina Kern Wheeler

J. Christopher Janak
Kristina Kern Wheeler
BOSE MCKINNEY &EVANS LLP
111 Monument Circle, Suite 2700
Indianapolis, Indiana 46204

WALMART INC.

Eric E. Kinder
SPILMAN THOMAS & BATTLE, PLLC
300 Kanawha Boulevard, East
P. O. Box 273
Charleston, WV 25321

Barry A. Naum
Steven W. Lee
SPILMAN THOMAS & BATTLE, PLLC
1100 Bent Creek Boulevard, Suite 101
Mechanicsburg, PA 17050

WABASH VALLEY POWER ASSOCIATION, INC.
D/B/A WABASH VALLEY POWER ALLIANCE

Jeremy L. Fetty
J. Michael Deweese
Leah Robyn Zoccola
PARR RICHEY
251 N. Illinois Street, Suite 1800
Indianapolis, IN 46204

Indiana Michigan Power Company - Cause Number 45933
Settlement Agreement Attachment A
(in 000s)

	Indiana Jurisdictional
Rate Base - 12/31/2024	5,423,700
Rate Base Adjustments (No Rounding)	
Increase Storm Reg Asset	6,077
Reduce Distribution Accumulated Depreciation	15,218
Remove Power Pay Net Plant	(378)
Adjusted Rate Base (With Rounding)	5,444,600
Return on Rate Base Impacts (With Rounding)	
Return on Equity ("ROE")	9.85%
ROE @ Settlement	(21,000)
NOL	(5,800)
GRCF	(500)
Rate Base Changes	1,700
Changes to Return on Rate Base	(25,600)
O&M Impacts (With Rounding)	
NOL Impact to Tax Expense	(3,900)
Other Expense	(6,000)
Nuclear Decommission Exp	(2,000)
Distribution Depreciation Expense	(15,800)
Reduce Storm Expense Amortization	(6,100)
Increase Ongoing Storm Expense in Base Rates	1,600
Misc IT Adjustments	(900)
Remove Power Pay Expense Amortization	(100)
Additional Tax Expense Reduction	(700)
Changes to O&M	(33,900)
Change in Ongoing Revenue Requirement *	(59,500)
Phase I Items (With Rounding)	
As filed Revenue Requirement**	116,400
Change in Ongoing Revenue Requirement*	(59,500)
Phase-In Credit	(34,200)
Annual Change to Phase I Revenue Requirement*	22,700
Phase II Items (With Rounding)	
As filed Revenue Requirement**	116,400
Change in Ongoing Revenue Requirement*	(59,500)
Annual Change to Phase II Revenue Requirement*	56,900

* Prior to updated Transmission Costs, Revenues and change in Rider Revenues as summarized on Settlement Attachment B

** Total Rate Change net of Transmission Costs, Revenues and change in Rider Revenues

Indiana Michigan Power Company - Cause Number 45933
Settlement Agreement Attachment B

INDIANA MICHIGAN POWER COMPANY
INDIANA JURISDICTIONAL PROJECTED REQUIRED RATE RELIEF SUMMARY
FOR THE TEST YEAR ENDED DECEMBER 31, 2024

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Source	Indiana Jurisdictional Settlement	Indiana Jurisdictional As-Filed	Variance
1	Adjusted Original Cost Rate Base	Exhibit A-6	$ 5,444,606,117	$ 5,423,706,117	$ 20,900,000
2	Required Rate of Return	Exhibit A-7	6.12%	6.49%	
3	Income Requirement	Line 1 x Line 2	$ 333,209,894	$ 351,998,527	$ (18,788,633)
4	Less: Net Electric Operating Income	Exhibit A-5	$ 284,835,850	$ 259,164,385	$ 25,671,465
5	Income Deficiency	Line 3 - Line 4	$ 48,374,045	$ 92,834,142	$ (44,460,097)
6	Gross Revenue Conversion Factor	Exhibit A-8	1.3358	1.3372	
7	Jurisdictional Revenue Deficiency	Line 5 x Line 6	$ 64,618,049	$ 124,137,815	$ (59,519,766)
8	Remove Transmission Owner Costs, Revenues	Attachment JLF-1	$ (2,773,080)	$ (8,237,860)	$ 5,464,780
9	Total Required Rate Relief Before Phase-In Credit	Line 7 + Line 8	$ 61,844,969	$ 115,899,955	$ (54,054,986)
10	Less: Current Revenue for Ongoing Riders	Attachment JLF-2	$ (382,250,710)	$ (382,250,710)	$ 0
11	Plus: Proposed Rider Revenue	Attachment JLF-2	$ 382,226,108	$ 382,726,978	$ (500,870)
12	Total Rate Change Before Phase-In Credit	Line 9 + Line 10 + Line 11	$ 61,820,367	$ 116,376,223	$ (54,555,856)
13	Forecasted Revenues Before Increase	Attachment JLF-2	$ 1,710,991,831	$ 1,710,991,831	
14	Percent Increase	Line 12 / Line 13	3.61%	6.80%	
15	Phase-In Credit	Attachment JCD-2	$ (34,205,275)	$ (32,692,077)	$ (1,513,198)
16	Total Rate Change During Phase-In	Line 12 + Line 15	$ 27,615,092	$ 83,684,146	$ (56,069,054)
17	Percent Increase	Line 16 / Line 13	1.61%	4.89%	

Indiana Michigan Power Company - Cause Number 45933
Settlement Agreement Attachment C
Revenue Allocation Summary

	Settlement Revenue Allocation by Class	
	$ Increase	% Increase
RS	27,862,101	5.19%
GS	7,947,036	3.18%
LGS	15,228,619	3.93%
IP	8,447,333	1.24%
MS	100,394	5.13%
WSS	652,311	4.91%
IS	22,369	4.83%
EHG	26,737	5.13%
OL	271,034	5.13%
SL	211,885	5.14%
Total	60,769,820	3.83%
Interruptible Revenue and Rider Changes	1,050,547	
Total Rate Change	61,820,367	

TARIFF F.W. - S.L.
(Fort Wayne Streetlighting - Customer Owned and Maintained System)

Availability of Service.

Available to the City of Fort Wayne, Indiana, for energy supplied through the streetlighting system that is owned and maintained by the Municipality.

Rate. (Tariff Code 525)

3.506¢ per kWh.

Applicable Riders.

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44.

Payment.

Bills will be rendered monthly and will be due and payable on the 15th day of each month succeeding that in which the service is rendered.

Ledger.

A ~~written~~ ledger shall be maintained in the collector app and shared by the Company and the City ~~by the Company~~ specifying the type, wattage, number, and location of lamps on the customer's streetlighting system. The customer shall be responsible for advising the Company of any changes affecting the type, wattage, number, and location of lamps in service that occur during the billing period.

The customer and Company will reconcile the total street lighting ledger annually and correct any known billing discrepancies. The annual reconciliation is to occur during the first billing period of each calendar year. Additionally, the customer and Company will mutually conduct annual field audits covering at least 5% of the total street lighting served under this tariff. Each year the area audited will change until the entire service area is reviewed. Discrepancies that are discovered during this audit will be corrected effective to the known date of error but in no case will this correction exceed one year.

(Cont'd on Sheet No. 32.1)

Indiana Michigan Power Company - Cause Number 45933
Settlement Agreement Attachment D

I.U.R.C. NO. 20 **ORIGINAL SHEET NO. 32.1**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

TARIFF F.W. - S.L.
(Fort Wayne Streetlighting - Customer Owned and Maintained System)
(Cont'd from Sheet No. 32)

Determination of Energy.

The kWh quantity used for each month for each lamp shall be determined by multiplying the lamp wattage by the number of hours of monthly operation shown for the particular month in ~~from~~ the following table, divided by 1,000. ~~The kWh used by lamps rated at values differing from those included in the following table shall be determined and added to the list as appropriate.~~

TOTAL ~~MONTHLY ENERGY CONSUMPTION IN KILOWATT HOURS PER SINGLE LAMP~~
~~STREETLIGHTS (S), OUTDOOR LIGHTS (O)~~
~~ALL NIGHT LAMPS(~~MONTHLY ADJUSTED HOURS OF ~~FOR~~ PHOTOCELL OPERATION TO TOTAL 4,000 HOUR OPERATION PER YEAR)

Month	No. of Hours
Jan	429
Feb	350
Mar	349
Apr	299
May	259
Jun	240
Jul	249
Aug	289
Sep	329
Oct	379
Nov	399
Dec	429
Total	4,000

~~TYPE OF LAMP AND APPROXIMATE LUMENS~~[1]	~~TOTAL WATTS~~	~~CANDLE POWER~~	~~JAN~~	~~FEB~~	~~MAR~~	~~APR~~	~~MAY~~	~~JUN~~	~~JUL~~	~~AUG~~	~~SEP~~	~~OCT~~	~~NOV~~	~~DEC~~
~~INCANDESCENT~~														
~~1,000 Lumens (S)~~	~~92~~	~~100~~	~~39~~	~~32~~	~~32~~	~~28~~	~~25~~	~~22~~	~~24~~	~~27~~	~~29~~	~~35~~	~~36~~	~~39~~
~~2,500 Lumens (S,O)~~	~~189~~	~~250~~	~~79~~	~~67~~	~~67~~	~~57~~	~~51~~	~~45~~	~~48~~	~~55~~	~~60~~	~~71~~	~~75~~	~~81~~

(Cont'd on Sheet No.

ISSUED BY	**EFFECTIVE FOR ELECTRIC SERVICE RENDERED**
STEVEN F. BAKER	**ON OR AFTER**
PRESIDENT	
FORT WAYNE, INDIANA	**ISSUED UNDER AUTHORITY OF THE**
	INDIANA UTILITY REGULATORY COMMISSION
	DATED
	IN CAUSE NO.

Indiana Michigan Power Company - Cause Number 45933
Settlement Agreement Attachment D

SODIUM VAPOR															
3,600 L	4,000 L	50W (S)	66	28	23	23	20	18	16	17	19	24	25	26	28
5,000 L	6,000 L	70W (S,O)	86	36	30	30	26	23	21	22	25	28	32	34	37
8,550 L	9,500 L	100W (S,O)	121	51	43	43	36	32	29	31	35	39	45	48	52
14,400 L	16,000 L	150W (S,O)	176	74	62	62	53	47	42	45	51	57	66	70	75
24,750 L	27,500 L	250W (S,O)	309	130	109	109	93	83	74	79	90	99	116	122	132
45,000 L	50,000 L	400W (S,O)	500	210	176	176	150	134	120	128	146	160	188	198	214
99,000 L	110,000 L	750W (S)[2]	827	315	264	264	225	201	180	192	219	240	282	297	324
METAL HALIDE															
8,750 L	10,500 L	100W (O)	156	67	55	55	47	41	37	39	45	51	59	63	67
10,800 L	14,000 L	175W (O)	216	91	76	76	65	58	52	55	63	69	81	86	92
17,000 L	20,500 L	250W (O)	301	127	106	106	90	81	72	77	88	96	113	119	129
28,800 L	36,000 L	400W (O)	474	199	167	167	142	127	114	121	138	152	178	188	203
LED															
(S,O)			1	1	1	1	1	1	1	1	1	1	1	1	1
(S,O)			2	1	1	1	1	1	1	1	1	1	1	1	1
(S,O)			3	1	1	1	1	1	1	1	1	1	1	1	1
(S,O)			4	2	1	1	1	1	1	1	1	1	2	2	2
(S,O)			5	2	2	2	2	1	1	1	1	2	2	2	2
(S,O)			6	3	2	2	2	2	1	2	2	2	2	2	3
(S,O)			7	3	2	2	2	2	2	2	2	2	3	3	3
(S,O)			8	3	3	3	2	2	2	2	2	3	3	3	3
(S,O)			9	4	3	3	3	2	2	2	3	3	3	4	4
(S,O)			10	4	4	4	3	3	2	3	3	3	4	4	4
(S,O)			11	5	4	4	3	3	3	3	3	4	4	4	5

(Cont'd on Sheet No.

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON OR AFTER

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO.

Indiana Michigan Power Company - Cause Number 45933
Settlement Agreement Attachment D

I.U.R.C. NO. 20 **ORIGINAL SHEET NO. 32.2**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

TARIFF F.W. - S.L.
(Fort Wayne Streetlighting - Customer Owned and Maintained System)

TYPE OF LAMP AND APPROX MATE LUMENS[1]	TOTAL WATTS	CANDLE POWER	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
(S,O)	12		5	4	4	4	3	3	3	3	4	5	5	5
(S,O)	13		6	5	5	4	3	3	3	4	4	5	5	6
(S,O)	14		6	5	5	4	4	3	4	4	5	5	6	6
(S,O)	15		6	5	5	5	4	4	4	4	5	6	6	6
(S,O)	16		7	6	6	5	4	4	4	5	5	6	6	7
(S,O)	17		7	6	6	5	4	4	4	5	6	6	7	7
(S,O)	18		8	6	6	5	5	4	5	5	6	7	7	8
(S,O)	19		8	7	7	6	5	5	5	5	6	7	8	8
(S,O)	20		9	7	7	6	5	5	5	6	7	8	8	9
(S,O)	21		9	7	7	6	6	5	5	6	7	8	8	9
(S,O)	22		9	8	8	7	6	5	6	6	7	8	9	9
(S,O)	23		10	8	8	7	6	5	6	7	7	9	9	10
(S,O)	24		10	8	8	7	6	6	6	7	8	9	10	10
(S,O)	25		11	9	9	8	7	6	6	7	8	9	10	11
(S,O)	26		11	9	9	8	7	6	7	7	8	10	10	11
(S,O)	27		12	9	9	8	7	6	7	8	9	10	11	12
(S,O)	28		12	10	10	8	7	7	7	8	9	11	11	12
(S,O)	29		12	10	10	9	8	7	7	8	9	11	12	12
(S,O)	30		13	11	11	9	8	7	8	9	10	11	12	13
(S,O)	31		13	11	11	9	8	7	8	9	10	12	12	13
(S,O)	32		14	11	11	10	8	8	8	9	10	12	13	14
(S,O)	33		14	12	12	10	9	8	8	10	11	12	13	14
(S,O)	34		14	12	12	10	9	8	9	10	11	13	14	14
(S,O)	35		15	12	12	11	9	8	9	10	11	13	14	16
(S,O)	36		15	13	13	11	9	9	9	10	12	14	14	15
(S,O)	37		16	13	13	11	10	9	9	11	12	14	15	16
(S,O)	38		16	13	13	11	10	9	10	11	12	14	15	16
(S,O)	39		17	14	14	12	10	9	10	11	13	15	16	17
(S,O)	40		17	14	14	12	11	10	10	12	13	15	16	17
(S,O)	41		17	14	14	12	11	10	10	12	13	15	16	17
(S,O)	42		18	15	15	13	11	10	11	12	14	16	17	18
(S,O)	43		18	15	15	13	11	10	11	12	14	16	17	18
(S,O)	44		19	15	15	13	12	10	11	13	14	17	18	19
(S,O)	45		19	16	16	14	12	11	11	13	15	17	18	19
(S,O)	46		20	16	16	14	12	11	12	13	15	17	18	20
(S,O)	47		20	17	17	14	12	11	12	14	15	18	19	20
(S,O)	48		20	17	17	14	13	11	12	14	16	18	19	20
(S,O)	49		21	17	17	15	13	12	12	14	16	18	20	21
(S,O)	50		21	18	18	15	13	12	13	14	16	19	20	21
(S,O)	51		22	18	18	15	13	12	13	15	17	19	20	22
(S,O)	52		22	18	18	16	14	12	13	15	17	20	21	22
(S,O)	53		23	19	19	16	14	13	13	15	17	20	21	23
(S,O)	54		23	19	19	16	14	13	14	16	18	20	22	23

(Cont'd on Sheet No.

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON OR AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO.

Indiana Michigan Power Company - Cause Number 45933
Settlement Agreement Attachment D

I.U.R.C. NO. 20 ORIGINAL SHEET NO. 32.3
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

TARIFF F.W. - S.L.
(Fort Wayne Streetlighting - Customer Owned and Maintained System)

TYPE OF LAMP AND APPROX MATE LUMENS[1]	TOTAL WATTS	CANDLE POWER	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
~~(S,O)~~	~~55~~		~~23~~	~~19~~	~~19~~	~~17~~	~~14~~	~~13~~	~~14~~	~~16~~	~~18~~	~~21~~	~~22~~	~~23~~
~~(S,O)~~	~~56~~		~~24~~	~~20~~	~~20~~	~~17~~	~~15~~	~~13~~	~~14~~	~~16~~	~~18~~	~~21~~	~~22~~	~~24~~
~~(S,O)~~	~~57~~		~~24~~	~~20~~	~~20~~	~~17~~	~~15~~	~~14~~	~~14~~	~~16~~	~~19~~	~~21~~	~~23~~	~~24~~
~~(S,O)~~	~~58~~		~~25~~	~~20~~	~~20~~	~~17~~	~~15~~	~~14~~	~~15~~	~~17~~	~~19~~	~~22~~	~~23~~	~~25~~
~~(S,O)~~	~~59~~		~~25~~	~~21~~	~~21~~	~~18~~	~~16~~	~~14~~	~~15~~	~~17~~	~~19~~	~~22~~	~~24~~	~~25~~
~~(S,O)~~	~~60~~		~~26~~	~~21~~	~~21~~	~~18~~	~~16~~	~~14~~	~~15~~	~~17~~	~~20~~	~~23~~	~~24~~	~~26~~
~~(S,O)~~	~~61~~		~~26~~	~~21~~	~~21~~	~~18~~	~~16~~	~~15~~	~~15~~	~~18~~	~~20~~	~~23~~	~~24~~	~~26~~
~~(S,O)~~	~~62~~		~~26~~	~~22~~	~~22~~	~~19~~	~~16~~	~~15~~	~~16~~	~~18~~	~~20~~	~~23~~	~~25~~	~~26~~
~~(S,O)~~	~~63~~		~~27~~	~~22~~	~~22~~	~~19~~	~~17~~	~~15~~	~~16~~	~~18~~	~~21~~	~~24~~	~~25~~	~~27~~
~~(S,O)~~	~~64~~		~~27~~	~~22~~	~~22~~	~~19~~	~~17~~	~~15~~	~~16~~	~~18~~	~~21~~	~~24~~	~~26~~	~~27~~
~~(S,O)~~	~~65~~		~~28~~	~~23~~	~~23~~	~~20~~	~~17~~	~~15~~	~~16~~	~~19~~	~~21~~	~~24~~	~~26~~	~~28~~
~~(S,O)~~	~~66~~		~~28~~	~~23~~	~~23~~	~~20~~	~~17~~	~~16~~	~~17~~	~~19~~	~~22~~	~~25~~	~~26~~	~~28~~
~~(S,O)~~	~~67~~		~~28~~	~~24~~	~~24~~	~~20~~	~~18~~	~~16~~	~~17~~	~~19~~	~~22~~	~~25~~	~~27~~	~~29~~
~~(S,O)~~	~~68~~		~~29~~	~~24~~	~~24~~	~~20~~	~~18~~	~~16~~	~~17~~	~~20~~	~~22~~	~~26~~	~~27~~	~~29~~
~~(S,O)~~	~~69~~		~~29~~	~~24~~	~~24~~	~~21~~	~~18~~	~~16~~	~~17~~	~~20~~	~~22~~	~~26~~	~~28~~	~~29~~
~~(S,O)~~	~~70~~		~~30~~	~~25~~	~~25~~	~~21~~	~~18~~	~~17~~	~~18~~	~~20~~	~~23~~	~~26~~	~~28~~	~~30~~
~~(S,O)~~	~~71~~		~~30~~	~~25~~	~~25~~	~~21~~	~~18~~	~~17~~	~~18~~	~~20~~	~~23~~	~~27~~	~~28~~	~~30~~
~~(S,O)~~	~~72~~		~~31~~	~~25~~	~~25~~	~~22~~	~~19~~	~~17~~	~~18~~	~~21~~	~~23~~	~~27~~	~~29~~	~~31~~
~~(S,O)~~	~~73~~		~~31~~	~~26~~	~~26~~	~~22~~	~~19~~	~~17~~	~~18~~	~~21~~	~~24~~	~~27~~	~~29~~	~~31~~
~~(S,O)~~	~~74~~		~~32~~	~~26~~	~~26~~	~~22~~	~~19~~	~~18~~	~~19~~	~~21~~	~~24~~	~~28~~	~~30~~	~~32~~
~~(S,O)~~	~~75~~		~~32~~	~~26~~	~~26~~	~~23~~	~~20~~	~~18~~	~~19~~	~~22~~	~~24~~	~~28~~	~~30~~	~~32~~
~~(S,O)~~	~~76~~		~~32~~	~~27~~	~~27~~	~~23~~	~~20~~	~~18~~	~~19~~	~~22~~	~~25~~	~~29~~	~~30~~	~~32~~
~~(S,O)~~	~~77~~		~~33~~	~~27~~	~~27~~	~~23~~	~~20~~	~~18~~	~~19~~	~~22~~	~~25~~	~~29~~	~~31~~	~~33~~
~~(S,O)~~	~~78~~		~~33~~	~~27~~	~~27~~	~~23~~	~~21~~	~~19~~	~~20~~	~~22~~	~~25~~	~~29~~	~~31~~	~~33~~
~~(S,O)~~	~~79~~		~~34~~	~~28~~	~~28~~	~~24~~	~~21~~	~~19~~	~~20~~	~~23~~	~~26~~	~~30~~	~~32~~	~~34~~
~~(S,O)~~	~~80~~		~~34~~	~~28~~	~~28~~	~~24~~	~~21~~	~~19~~	~~20~~	~~23~~	~~26~~	~~30~~	~~32~~	~~34~~
~~(S,O)~~	~~81~~		~~35~~	~~28~~	~~28~~	~~24~~	~~21~~	~~19~~	~~20~~	~~23~~	~~26~~	~~30~~	~~33~~	~~35~~
~~(S,O)~~	~~82~~		~~35~~	~~29~~	~~29~~	~~25~~	~~22~~	~~20~~	~~21~~	~~24~~	~~27~~	~~31~~	~~33~~	~~35~~
~~(S,O)~~	~~83~~		~~35~~	~~29~~	~~29~~	~~25~~	~~22~~	~~20~~	~~21~~	~~24~~	~~27~~	~~31~~	~~33~~	~~35~~
~~(S,O)~~	~~84~~		~~36~~	~~29~~	~~29~~	~~25~~	~~22~~	~~20~~	~~21~~	~~24~~	~~27~~	~~32~~	~~34~~	~~36~~
~~(S,O)~~	~~85~~		~~36~~	~~30~~	~~30~~	~~26~~	~~22~~	~~20~~	~~21~~	~~25~~	~~28~~	~~32~~	~~34~~	~~36~~
~~(S,O)~~	~~86~~		~~37~~	~~30~~	~~30~~	~~26~~	~~23~~	~~20~~	~~22~~	~~25~~	~~28~~	~~32~~	~~35~~	~~37~~
~~(S,O)~~	~~87~~		~~37~~	~~31~~	~~31~~	~~26~~	~~23~~	~~21~~	~~22~~	~~25~~	~~28~~	~~33~~	~~35~~	~~37~~
~~(S,O)~~	~~88~~		~~38~~	~~31~~	~~31~~	~~26~~	~~23~~	~~21~~	~~22~~	~~25~~	~~29~~	~~33~~	~~35~~	~~38~~
~~(S,O)~~	~~89~~		~~38~~	~~31~~	~~31~~	~~27~~	~~23~~	~~21~~	~~22~~	~~26~~	~~29~~	~~33~~	~~36~~	~~38~~
~~(S,O)~~	~~90~~		~~38~~	~~32~~	~~32~~	~~27~~	~~24~~	~~21~~	~~23~~	~~26~~	~~29~~	~~34~~	~~36~~	~~38~~
~~(S,O)~~	~~91~~		~~39~~	~~32~~	~~32~~	~~27~~	~~24~~	~~22~~	~~23~~	~~26~~	~~30~~	~~34~~	~~37~~	~~39~~
~~(S,O)~~	~~92~~		~~39~~	~~32~~	~~32~~	~~28~~	~~24~~	~~22~~	~~23~~	~~27~~	~~30~~	~~35~~	~~37~~	~~39~~
~~(S,O)~~	~~93~~		~~40~~	~~33~~	~~33~~	~~28~~	~~24~~	~~22~~	~~23~~	~~27~~	~~30~~	~~35~~	~~37~~	~~40~~
~~(S,O)~~	~~94~~		~~40~~	~~33~~	~~33~~	~~28~~	~~25~~	~~22~~	~~24~~	~~27~~	~~31~~	~~35~~	~~38~~	~~40~~
~~(S,O)~~	~~95~~		~~41~~	~~33~~	~~33~~	~~29~~	~~25~~	~~23~~	~~24~~	~~27~~	~~31~~	~~36~~	~~38~~	~~41~~
~~(S,O)~~	~~96~~		~~41~~	~~34~~	~~34~~	~~29~~	~~25~~	~~23~~	~~24~~	~~28~~	~~31~~	~~36~~	~~39~~	~~41~~
~~(S,O)~~	~~97~~		~~41~~	~~34~~	~~34~~	~~29~~	~~26~~	~~23~~	~~24~~	~~28~~	~~32~~	~~36~~	~~39~~	~~41~~

(Cont'd on Sheet No.

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON OR AFTER

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO.

Indiana Michigan Power Company - Cause Number 45933
Settlement Agreement Attachment D

I.U.R.C. NO. 20 **ORIGINAL SHEET NO. 32.4**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

TARIFF F.W. - S.L.
(Fort Wayne Streetlighting - Customer Owned and Maintained System)

TYPE OF LAMP AND APPROXIMATE LUMENS[1]	TOTAL WATTS	CANDLE POWER	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
(S,O)	98		42	34	34	29	26	23	25	28	32	37	39	42
(S,O)	99		42	35	35	30	26	24	25	29	32	37	40	42
(S,O)	100		43	35	35	30	26	24	25	29	33	38	40	43
(S,O)	101		43	35	35	30	27	24	25	29	33	38	41	43
(S,O)	102		43	36	36	31	27	24	26	29	33	38	41	43
(S,O)	103		44	36	36	31	27	25	26	30	34	39	41	44
(S,O)	104		44	37	37	31	27	25	26	30	34	39	42	44
(S,O)	105		45	37	37	32	28	25	26	30	34	39	42	45
(S,O)	106		45	37	37	32	28	25	27	31	35	40	43	45
(S,O)	107		46	38	38	32	28	25	27	31	35	40	43	46
(S,O)	108		46	38	38	33	28	26	27	31	35	41	43	46
(S,O)	109		46	38	38	33	29	26	27	31	36	41	44	46
(S,O)	110		47	39	39	33	29	26	28	32	36	41	44	47
(S,O)	111		47	39	39	33	29	26	28	32	36	42	45	47
(S,O)	112		48	39	39	34	29	27	28	32	37	42	45	48
(S,O)	113		48	40	40	34	30	27	28	33	37	43	45	48
(S,O)	114		49	40	40	34	30	27	29	33	37	43	46	49
(S,O)	115		49	40	40	35	30	27	29	33	37	43	46	49
(S,O)	116		49	41	41	35	31	28	29	33	38	44	47	49
(S,O)	117		50	41	41	35	31	28	29	34	38	44	47	50
(S,O)	118		50	41	41	36	31	28	30	34	38	44	47	50
(S,O)	119		51	42	42	36	31	28	30	34	39	45	48	51
(S,O)	120		51	42	42	36	32	29	30	35	39	45	48	51
(S,O)	121		52	42	42	36	32	29	30	35	39	46	49	52
(S,O)	122		52	43	43	37	32	29	31	35	40	46	49	52
(S,O)	123		52	43	43	37	32	29	31	35	40	46	49	52
(S,O)	124		53	44	44	37	33	30	31	36	40	47	50	53
(S,O)	125		53	44	44	38	33	30	31	36	41	47	50	53
(S,O)	126		54	44	44	38	33	30	32	36	41	47	51	54
(S,O)	127		54	45	45	38	33	30	32	37	41	48	51	54
(S,O)	128		55	45	45	39	34	30	32	37	42	48	51	55
(S,O)	129		55	45	45	39	34	31	32	37	42	49	52	55
(S,O)	130		55	46	46	39	34	31	33	37	42	49	52	55
(S,O)	131		56	46	46	39	34	31	33	38	43	49	53	56
(S,O)	132		56	46	46	40	35	31	33	38	43	50	53	56
(S,O)	133		57	47	47	40	35	32	33	38	43	50	53	57
(S,O)	134		57	47	47	40	35	32	34	39	44	50	54	57
(S,O)	135		58	47	47	41	36	32	34	39	44	51	54	58
(S,O)	136		58	48	48	41	36	32	34	39	44	51	55	58
(S,O)	137		58	48	48	41	36	33	34	40	45	52	55	58
(S,O)	138		59	48	48	42	36	33	35	40	45	52	55	59
(S,O)	139		59	49	49	42	37	33	35	40	45	52	56	59
(S,O)	140		60	49	49	42	37	33	35	40	46	53	56	60

(Cont'd on Sheet No.

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON OR AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO.

Indiana Michigan Power Company - Cause Number 45933
Settlement Agreement Attachment D

I.U.R.C. NO. 20 **ORIGINAL SHEET NO. 32.5**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

TARIFF F.W. - S.L.
(Fort Wayne Streetlighting - Customer Owned and Maintained System)

TYPE OF LAMP AND APPROX MATE LUMENS[1]	TOTAL WATTS	CANDLE POWER	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
(S,O)	141		60	50	50	42	37	34	35	41	46	53	57	60
(S,O)	142		61	50	50	43	37	34	36	41	46	53	57	61
(S,O)	143		61	50	50	43	38	34	36	41	47	54	57	61
(S,O)	144		61	51	51	43	38	34	36	42	47	54	58	61
(S,O)	145		62	51	51	44	38	35	36	42	47	55	58	62
(S,O)	146		62	51	51	44	38	35	37	42	48	55	59	62
(S,O)	147		63	52	52	44	39	35	37	42	48	55	59	63
(S,O)	148		63	52	52	45	39	35	37	43	48	56	59	63
(S,O)	149		64	52	52	45	39	35	37	43	49	56	60	64
(S,O)	150		64	53	53	45	39	36	38	43	49	56	60	64
(S,O)	151		64	53	53	45	40	36	38	44	49	57	61	64
(S,O)	152		65	53	53	46	40	36	38	44	50	57	61	65
(S,O)	153		65	54	54	46	40	36	38	44	50	58	61	65
(S,O)	154		66	54	54	46	41	37	39	44	50	58	62	66
(S,O)	155		66	54	54	47	41	37	39	45	51	58	62	66
(S,O)	156		67	55	55	47	41	37	39	45	51	59	63	67
(S,O)	157		67	55	55	47	41	37	39	45	51	59	63	67
(S,O)	158		67	55	55	48	42	38	40	46	52	59	63	67
(S,O)	159		68	56	56	48	42	38	40	46	52	60	64	68
(S,O)	160		68	56	56	48	42	38	40	46	52	60	64	68
(S,O)	161		69	57	57	48	42	38	40	46	52	61	65	69
(S,O)	162		69	57	57	49	43	38	41	47	53	61	65	69
(S,O)	163		69	57	57	49	43	39	41	47	53	61	65	69
(S,O)	164		70	58	58	49	43	39	41	47	53	62	66	70
(S,O)	165		70	58	58	50	43	39	41	48	54	62	66	70
(S,O)	166		71	58	58	50	44	40	42	48	54	62	67	71
(S,O)	167		71	59	59	50	44	40	42	48	54	63	67	71
(S,O)	168		72	59	59	51	44	40	42	48	55	63	67	72
(S,O)	169		72	59	59	51	45	40	42	49	55	64	68	72
(S,O)	170		72	60	60	51	45	41	43	49	55	64	68	72
(S,O)	171		73	60	60	51	45	41	43	49	56	64	69	73
(S,O)	172		73	60	60	52	45	41	43	50	56	65	69	73
(S,O)	173		74	61	61	52	46	41	43	50	56	65	69	74
(S,O)	174		74	61	61	52	46	41	44	50	57	65	70	74
(S,O)	175		75	61	61	53	46	42	44	50	57	66	70	75
(S,O)	176		75	62	62	53	46	42	44	51	57	66	71	75
(S,O)	177		75	62	62	53	47	42	44	51	58	67	71	75
(S,O)	178		76	62	62	54	47	42	45	51	58	67	71	76
(S,O)	179		76	63	63	54	47	43	45	52	58	67	72	76
(S,O)	180		77	63	63	54	47	43	45	52	59	68	72	77
(S,O)	181		77	64	64	54	48	43	45	52	59	68	73	77
(S,O)	182		78	64	64	55	48	43	46	52	59	68	73	78
(S,O)	183		78	64	64	55	48	44	46	53	60	69	73	78

(Cont'd on Sheet No.

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON OR AFTER

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO.

Indiana Michigan Power Company - Cause Number 45933
Settlement Agreement Attachment D

I.U.R.C. NO. 20 — ORIGINAL SHEET NO. 32.6
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

TARIFF F.W. - S.L.
(Fort Wayne Streetlighting - Customer Owned and Maintained System)

TYPE OF LAMP AND APPROX MATE LUMENS[1]	TOTAL WATTS	CANDLE POWER	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
(S,O)	184		78	65	65	55	48	44	46	53	60	69	74	78
(S,O)	185		79	65	65	56	49	44	46	53	60	70	74	79
(S,O)	186		79	65	65	56	49	44	47	54	61	70	75	79
(S,O)	187		80	66	66	56	49	45	47	54	61	70	75	80
(S,O)	188		80	66	66	57	50	45	47	54	61	71	75	80
(S,O)	189		81	66	66	57	50	45	47	55	62	71	76	81
(S,O)	190		81	67	67	57	50	45	48	55	62	71	76	81
(S,O)	191		81	67	67	57	50	46	48	55	62	72	77	81
(S,O)	192		82	67	67	58	51	46	48	55	63	72	77	82
(S,O)	193		82	68	68	58	51	46	48	56	63	73	77	82
(S,O)	194		83	68	68	58	51	46	49	56	63	73	78	83
(S,O)	195		83	68	68	59	51	46	49	56	64	73	78	83
(S,O)	196		84	69	69	59	52	47	49	57	64	74	79	84
(S,O)	197		84	69	69	59	52	47	49	57	64	74	79	84
(S,O)	198		84	70	70	60	52	47	50	57	65	74	79	84
(S,O)	199		85	70	70	60	52	47	50	57	65	75	80	85
(S,O)	200		85	70	70	60	53	48	50	58	65	75	80	85
(S,O)	201		86	71	71	60	53	48	50	58	66	76	81	86
(S,O)	202		86	71	71	61	53	48	51	58	66	76	81	86
(S,O)	203		87	71	71	61	53	48	51	59	66	76	81	87
(S,O)	204		87	72	72	61	54	49	51	59	67	77	82	87
(S,O)	205		87	72	72	62	54	49	51	59	67	77	82	87
(S,O)	206		88	72	72	62	54	49	52	59	67	77	83	88
(S,O)	207		88	73	73	62	55	49	52	60	67	78	83	88
(S,O)	208		89	73	73	63	55	50	52	60	68	78	83	89
(S,O)	209		89	73	73	63	55	50	52	60	68	79	84	89
(S,O)	210		90	74	74	63	55	50	53	61	68	79	84	90
(S,O)	211		90	74	74	63	56	50	53	61	69	79	85	90
(S,O)	212		90	74	74	64	56	51	53	61	69	80	85	90
(S,O)	213		91	75	75	64	56	51	53	61	69	80	85	91
(S,O)	214		91	75	75	64	56	51	54	62	70	81	86	91
(S,O)	215		92	75	75	65	57	51	54	62	70	81	86	92
(S,O)	216		92	76	76	65	57	51	54	62	70	81	87	92
(S,O)	217		93	76	76	65	57	52	54	63	71	82	87	93
(S,O)	218		93	77	77	66	57	52	55	63	71	82	87	93
(S,O)	219		93	77	77	66	58	52	55	63	71	82	88	93
(S,O)	220		94	77	77	66	58	52	55	63	72	83	88	94
(S,O)	221		94	78	78	67	58	53	55	64	72	83	89	94
(S,O)	222		95	78	78	67	58	53	56	64	72	84	89	95
(S,O)	223		95	78	78	67	59	53	56	64	73	84	89	95
(S,O)	224		95	79	79	67	59	53	56	65	73	84	90	95
(S,O)	225		96	79	79	68	59	54	56	65	73	85	90	96
(S,O)	226		96	79	79	68	60	54	57	65	74	85	91	96

~~(Cont'd on Sheet No. 32.7)~~

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON OR AFTER

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO.

Indiana Michigan Power Company - Cause Number 45933
Settlement Agreement Attachment D

I.U.R.C. NO. 20 **ORIGINAL SHEET NO. 32.7**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

TARIFF F.W. - S.L.
(Fort Wayne Streetlighting - Customer Owned and Maintained System)

TYPE OF LAMP AND APPROX MATE LUMENS[1]	TOTAL WATTS	CANDLE POWER	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
(S,O)	227		97	80	80	68	60	54	67	65	74	85	91	97
(S,O)	228		97	80	80	69	60	54	57	66	74	86	91	97
(S,O)	229		98	80	80	69	60	55	57	66	75	86	92	98
(S,O)	230		98	81	81	69	61	55	58	66	75	87	92	98
(S,O)	231		98	81	81	70	61	55	58	67	75	87	93	98
(S,O)	232		99	81	81	70	61	55	58	67	76	87	93	99
(S,O)	233		99	82	82	70	61	56	58	67	76	88	93	99
(S,O)	234		100	82	82	70	62	56	59	67	76	88	94	100
(S,O)	235		100	83	83	71	62	56	59	68	77	88	94	100
(S,O)	236		101	83	83	71	62	56	59	68	77	89	95	101
(S,O)	237		101	83	83	71	62	56	59	68	77	89	95	101
(S,O)	238		101	84	84	72	63	57	60	69	78	90	95	101
(S,O)	239		102	84	84	72	63	57	60	69	78	90	96	102
(S,O)	240		102	84	84	72	63	67	60	69	78	90	96	102
(S,O)	241		103	85	85	73	63	57	60	70	79	91	97	103
(S,O)	242		103	85	85	73	64	58	61	70	79	91	97	103
(S,O)	243		104	85	85	73	64	58	61	70	79	91	98	104
(S,O)	244		104	86	86	73	64	58	61	70	80	92	98	104
(S,O)	245		104	86	86	74	65	58	61	71	80	92	98	104
(S,O)	246		105	86	86	74	65	59	62	71	80	93	99	105
(S,O)	247		105	87	87	74	65	59	62	71	81	93	99	105
(S,O)	248		106	87	87	75	65	59	62	72	81	93	100	106
(S,O)	249		106	87	87	75	66	59	62	72	81	94	100	106
(S,O)	250		107	88	88	75	66	60	63	72	82	94	100	107
(S,O)	251		107	88	88	76	66	60	63	72	82	94	101	107
(S,O)	252		107	88	88	76	66	60	63	73	82	95	101	107
(S,O)	253		108	89	89	76	67	60	63	73	82	95	102	108
(S,O)	254		108	89	89	76	67	61	64	73	83	96	102	108
(S,O)	255		109	90	90	77	67	61	64	74	83	96	102	109
(S,O)	256		109	90	90	77	67	61	64	74	83	96	103	109
(S,O)	257		110	90	90	77	68	61	64	74	84	97	103	110
(S,O)	258		110	91	91	78	68	61	65	74	84	97	104	110
(S,O)	259		110	91	91	78	68	62	65	75	84	97	104	110
(S,O)	260		111	91	91	78	68	62	65	75	85	98	104	111
(S,O)	261		111	92	92	79	69	62	65	75	85	98	105	111
(S,O)	262		112	92	92	79	69	62	66	76	85	99	105	112
(S,O)	263		112	92	92	79	69	63	66	76	86	99	106	112
(S,O)	264		113	93	93	79	70	63	66	76	86	99	106	113
(S,O)	265		113	93	93	80	70	63	66	76	86	100	106	113
(S,O)	266		113	93	93	80	70	63	67	77	87	100	107	113
(S,O)	267		114	94	94	80	70	64	67	77	87	100	107	114
(S,O)	268		114	94	94	81	71	64	67	77	87	101	108	114
(S,O)	269		115	94	94	81	71	64	67	78	88	101	108	115

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON OR AFTER

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO.

Indiana Michigan Power Company - Cause Number 45933
Settlement Agreement Attachment D

I.U.R.C. NO. 20 **ORIGINAL SHEET NO. 32.8**
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

TARIFF F.W. - S.L.
(Fort Wayne Streetlighting - Customer Owned and Maintained System)

APPROXIMATE LUMENS[1]	WATTS	POWER	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
(S,O)	270		115	95	95	81	71	64	68	78	88	102	108	115
(S,O)	271		116	95	95	82	71	65	68	78	88	102	109	116
(S,O)	272		116	95	95	82	72	65	68	78	89	102	109	116
(S,O)	273		116	96	96	82	72	65	68	79	89	103	110	116
(S,O)	274		117	96	96	82	72	65	69	79	89	103	110	117
(S,O)	275		117	97	97	83	72	66	69	79	90	103	110	117
(S,O)	276		118	97	97	83	73	66	69	80	90	104	111	118
(S,O)	277		118	97	97	83	73	66	69	80	90	104	111	118
(S,O)	278		119	98	98	84	73	66	70	80	91	105	112	119
(S,O)	279		119	98	98	84	73	66	70	80	91	105	112	119
(S,O)	280		119	98	98	84	74	67	70	81	91	105	112	119
(S,O)	281		120	99	99	85	74	67	70	81	92	106	113	120
(S,O)	282		120	99	99	85	74	67	71	81	92	106	113	120
(S,O)	283		121	99	99	85	75	67	71	82	92	106	114	121
(S,O)	284		121	100	100	85	75	68	71	82	93	107	114	121
(S,O)	285		122	100	100	86	75	68	71	82	93	107	114	122
(S,O)	286		122	100	100	86	75	68	72	82	93	108	115	122
(S,O)	287		122	101	101	86	76	68	72	83	94	108	115	122
(S,O)	288		123	101	101	87	76	69	72	83	96	108	116	123
(S,O)	289		123	101	101	87	76	69	72	83	94	109	116	123
(S,O)	290		124	102	102	87	76	69	73	84	95	109	116	124
(S,O)	291		124	102	102	88	77	69	73	84	95	109	117	124
(S,O)	292		124	103	103	88	77	70	73	84	96	110	117	124
(S,O)	293		125	103	103	88	77	70	73	85	96	110	118	125
(S,O)	294		125	103	103	88	77	70	74	85	96	111	118	125
(S,O)	295		126	104	104	89	78	70	74	85	96	111	118	126
(S,O)	296		126	104	104	89	78	71	74	85	97	111	119	126
(S,O)	297		127	104	104	89	78	71	74	86	97	112	119	127
(S,O)	298		127	105	105	90	78	71	75	86	97	112	120	127
(S,O)	299		127	105	105	90	79	71	75	86	97	112	120	127
(S,O)	300		128	105	105	90	79	71	75	87	98	113	120	128

NOTE: For half-night (time clock) lamps multiply consumption by 0.5 or for a 7-hour timer multiply by 0.63875. [1]Lumen Output for Mercury Vapor, Sodium Vapor, and Metal Halide listed in this table as mean lumens in first column and initial lumens in the second column. Lumen rating varies with lamp manufacturer.
[2]City of Fort Wayne, IN only.

Special Terms and Conditions.

This tariff is subject to the Company's Terms and Conditions of Service.

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED ON OR AFTER

ISSUED UNDER AUTHORITY OF THE INDIANA UTILITY REGULATORY COMMISSION
DATED
IN CAUSE NO.

STATE OF IOWA
DEPARTMENT OF COMMERCE
IOWA UTILITIES BOARD

IN RE:	:	**DOCKET NO. RPU-2022-____**
MIDAMERICAN ENERGY COMPANY	:	

DIRECT TESTIMONY
OF
ANN E. BULKLEY

January 2022

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Ann E. Bulkley. My business address is One Beacon Street, Suite 2600, Boston, Massachusetts 02108. I am employed by The Brattle Group. ("Brattle") as a Principal.

Q. On whose behalf are you submitting this Prepared Direct Testimony?

A. I am submitting this testimony before the Iowa Utilities Board ("IUB" or "Board") on behalf of MidAmerican Energy Company ("MidAmerican" or "the Company").

Q. Please describe your education and experience.

A. I hold a Bachelor's degree in Economics and Finance from Simmons College and a Master's degree in Economics from Boston University, with more than 25 years of experience consulting to the energy industry. I have advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. I have included my resume and a summary of testimony that I have filed in other proceedings as MidAmerican Bulkley Direct Testimony-Appendix 1.

Q. Please describe the purpose of your testimony.

A. The purpose of my testimony is to sponsor the proposed Return on Equity ("ROE") ratemaking principle for MidAmerican's Wind PRIME project ("Wind PRIME" or "Project") and to present evidence as to whether the Company's requested ROE of 11.25

percent is reasonable and appropriate. In addition, the Company has requested my opinion on the appropriateness of a 10.00 percent ROE to be used in the calculation of the Allowance for Funds Used During Construction ("AFUDC").

Q. What is the Company's proposed return on equity for this project?

A. The Company is requesting an ROE of 11.25 percent for the Project.

Q. How did you estimate the reasonableness of the Company's requested ROEs?

A. I estimated the cost of equity by applying several traditional ROE estimation methodologies to a proxy group of comparable utilities including the Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM"), Empirical CAPM ("ECAPM"), and Bond Yield Risk Premium ("BYRP" or "Risk Premium") methodologies to determine the investor required return in the current market. I used this estimate to assess the reasonableness of the Company's proposed ROE to calculate AFUDC. I then considered a reasonable adjustment to reflect the incremental risk associated with fixing the ROE for a 30 to 40- year period for Wind PRIME and compared the result to the requested ROE of 11.25 percent.

Q. What are your conclusions from that analysis?

A. The results of my analyses are presented in MidAmerican Bulkley Direct Exhibit-ROE, Schedules 1 through 8. Figure 1 below summarizes the results of the traditional ROE estimation methodologies. Based on the range established by these analyses, and considering the current and expected market conditions, and the risks associated with generation, I conclude that a reasonable range of returns is between 9.90 percent and 10.50 percent and within that range a return of 10.30 percent would be reasonable.

Figure 1: Summary of Cost of Equity Analytical Results[1]

Constant Growth DCF – Median			
	Median Low	Median	Median High
30-Day Average	8.83%	9.54%	10.46%
90-Day Average	8.78%	9.61%	10.36%
180-Day Average	8.80%	9.54%	10.25%
Constant Growth DCF - Average w/ exclusions			
	Mean Low	Mean	Mean High
30-Day Average	8.73%	9.40%	10.26%
90-Day Average	8.69%	9.36%	10.22%
180-Day Average	8.83%	9.37%	10.23%
CAPM			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Value Line Beta	11.63%	11.69%	11.80%
Bloomberg Beta	10.85%	10.94%	11.12%
Long-Term Avg. Beta	9.84%	9.98%	10.25%
ECAPM			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Value Line Beta	11.96%	12.01%	12.09%
Bloomberg Beta	11.38%	11.45%	11.58%
Long-Term Avg. Beta	10.63%	10.73%	10.93%
Treasury Yield Plus Risk Premium			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Risk Premium Analysis	9.52%	9.73%	10.13%

[1] Constant Growth DCF analysis - Average w/ Exclusions represents the DCF results excluding the results for individual companies that did not meet the minimum threshold of 7 percent.

Q. Is there incremental risk associated with fixing the return on equity over a 30-40 year period, which is the expected life of the assets that are the subject of this proceeding?

A. Yes. While current capital costs are low as compared with historical costs, there is no guarantee that costs will remain at these levels. Further, as discussed in Section III of my testimony, recent and projected market conditions indicate that the investor-required return on equity is expected to be increasing in the near term. Finally, as discussed in more detail in Section V.D of my testimony, reviewing historical data from 1992 through the 2018, the average authorized ROE for electric utilities in base rate proceedings has been variable. Therefore, over the 30-to-40-year period that this return will be in effect, it is reasonable to expect variability in the cost of equity. For this project, where the cost of equity would be fixed over time, if equity returns increase, the Company is assuming the risk that the authorized return may not be sufficient to meet the investor-required return on equity.

Q. Have you evaluated the reasonableness of this proposed return on equity?

A. Yes, I have. I have considered the ROE request in two components, a base ROE and an incremental adjustment to reflect the risk associated with fixing the ROE over a 30 to 40 - year time period. I have estimated the base ROE using current market data and the results of the traditional ROE estimation methodologies. In addition, I have estimated a reasonable return differential that adjusts for the incremental risk associated with fixing the ROE over the time-period discussed for this project. In that analysis, I compare the Board's historically authorized ROEs in advance ratemaking principles ("ARP") cases as compared with the national annual average authorized ROE for utility base rate cases across state regulatory jurisdictions for the same time period. For example, if the Company received

ARP on a project in 2002, I compared the authorized ROE in that case to the average of authorized ROEs for utility base rate proceedings in the calendar year 2002.

Q. What are your conclusions regarding the reasonableness of MidAmerican's requested ROE of 11.25 percent?

A. I conclude that an ROE of 11.25 percent is reasonable and appropriate based on the following considerations: (1) the range of results estimated using traditional ROE estimation methodologies and current and projected market data, and (2) an analysis of the average difference between the Board's authorized ROEs in MidAmerican's prior ARP proceedings and the national average authorized ROE in utility rate cases over time.

Q. What is your conclusion regarding the Company's requested 10.00 percent return on equity for purposes of calculating AFUDC?

A. The Company's requested return on equity for purposes of calculating AFUDC is lower than my estimate of the investor-required return on equity currently. Therefore, I believe that this request is reasonable.

Q. Have you prepared any schedules that support your conclusions?

A. Yes. My analyses and recommendations are supported by the data presented in MidAmerican Bulkley Direct Exhibit-ROE, Schedules 3 through 7, which were prepared by me or under my direction.

Q. How is the remainder of your testimony organized?

A. Section II reviews the regulatory guidelines pertinent to the development of the cost of equity. Section III discusses current and projected capital market conditions and the effect of those conditions on MidAmerican's cost of equity. Section IV explains my selection of a proxy group of electric utilities. Section V describes my analyses and the analytical basis for the recommendation of the appropriate base ROE for MidAmerican. Section VI provides an analysis of the incremental return that has been authorized above investor required returns in prior proceedings where advance ratemaking principles were determined to reflect the return on the incremental risk associated with fixing the ROE over the recovery period for the asset. Section VII presents my conclusions and recommendations for the market cost of equity.

II. REGULATORY GUIDELINES

Q. Please describe the guiding principles to be used in establishing the cost of equity for a regulated utility.

A. The United States Supreme Court's precedent-setting *Hope and Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's allowed ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) the principle that the result reached, as opposed to the methodology employed, is the controlling factor in arriving at just and reasonable rates.[2]

[2] *Hope*, 320 U.S. 591 (1944); *Bluefield*, 262 U.S. 679 (1923).

Q. Has the IUB provided similar guidance in establishing the appropriate return on common equity?

A. Yes. The Board follows the precedents of the *Hope* and *Bluefield* cases and acknowledges that utility investors are entitled to a fair and reasonable return. This position was set forth by the Board as follows:

> [i]n setting an allowed rate of return on equity investment, the Board is to balance investor and consumer interests. For example, if rates produce earnings that are below a fair and reasonable level, they may be unjust or confiscatory to the owners of the utility property; if rates produce earnings that are above a fair and reasonable level, the rates may be oppressive to the utility's ratepayers. Davenport Water Co., v. Iowa State Commerce Comm'n, 190 N.W.2d 583, 604-605 (Iowa 1971). In addition, the U.S. Supreme Court in Federal Power Commission v. Hope Natural Gas Company, 320 US 591 (1944), held that "the return to the equity owner [the utility] should be commensurate with returns on investments in other enterprises having corresponding risks. The return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain credit and attract capital...."
>
> In determining the allowed return, the various models generally produce a range for the Board to consider. There is no precise return on equity that is accurate or only one that is appropriate, but a range of reasonable returns. Within that range, the Board determines the most appropriate return, balancing the interests of shareholders and ratepayers.[3]

Based on these standards, the authorized ROE should provide the Company with a fair and reasonable return and should provide access to capital on reasonable terms in a variety of market conditions.

[3] Iowa Utilities Board, In RE: MidAmerican Energy Company, Docket No. RPU-2013-0004, Order Approving Settlement, With Modifications, and Requiring Additional Information, March 17 2014, at 20-21.

Q. Why is it important for a utility to be allowed the opportunity to earn an ROE that is adequate to attract capital at reasonable terms?

A. An ROE that is adequate to attract capital at reasonable terms enables the Company to continue to provide safe, reliable electric service while maintaining its financial integrity. That return should be commensurate with returns expected elsewhere in the market for investments of equivalent risk. If it is not, debt and equity investors will seek alternative investment opportunities for which the expected return reflects the perceived risks, thereby inhibiting the Company's ability to attract capital at reasonable cost.

Q. Is a utility's ability to attract capital also affected by the ROEs that are authorized for other utilities?

A. Yes. Utilities compete directly for capital with other investments of similar risk, which include other vertically integrated electric utilities. The ROE awarded to a utility sends an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, growth, and fair compensation for business and financial risk. The cost of capital represents an opportunity cost to investors. If higher returns are available for other investments of comparable risk, investors have an incentive to direct their capital to those investments. Thus, an authorized ROE that is not commensurate with authorized ROEs for other vertically integrated electric utilities can inhibit the utility's ability to attract capital for investment.

Q. What are your conclusions regarding regulatory guidelines?

A. The ratemaking process is premised on the principle that a utility must have the opportunity to recover the return of, and the market-required return on, its invested capital. Because utility operations are capital-intensive, regulatory decisions should enable the utility to attract capital at reasonable terms under a variety of economic and financial market conditions; doing so balances the long-term interests of the utility and its customers.

The financial community carefully monitors the current and expected financial condition of utility companies and the regulatory frameworks in which they operate. In that respect, the regulatory framework is one of the most important factors in both debt and equity investors' assessments of risk. The Board's order in this proceeding, therefore, should provide the Company with the opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable terms under a variety of economic and financial market conditions over the period of time that this asset will be recovered; (2) sufficient to ensure good financial management and firm integrity; and (3) commensurate with returns on investments in enterprises with similar risk. Providing the opportunity to earn a market-based cost of capital supports the financial integrity of the Company, which is in the interest of both customers and shareholders.

III. CAPITAL MARKET CONDITIONS

Q. Why is it important to analyze capital market conditions?

A. The ROE estimation models rely on market data that are either specific to the proxy group, in the case of the DCF model, or to the expectations of market risk, in the case of the CAPM. The results of the ROE estimation models can be affected by prevailing market conditions at the time the analysis is performed. While the ROE that is established in a rate proceeding is intended to be forward-looking, the analyst uses current and projected market data, specifically stock prices, dividends, growth rates and interest rates in the ROE estimation models to estimate the required return for the subject company.

As discussed in the remainder of this section, analysts and regulatory commissions have concluded that current market conditions have affected the results of the ROE estimation models. As a result, it is important to consider the effect of these conditions on the ROE estimation models when determining the appropriate range and recommended ROE for a future period. If investors do not expect current market conditions to be sustained in the future, it is possible that the ROE estimation models will not provide an accurate estimate of investors' required return during that rate period. Therefore, it is very important to consider projected market data to estimate the return for that forward-looking period.

Q. What factors are affecting the cost of equity for regulated utilities in the current and prospective capital markets?

A. The cost of equity for regulated utility companies is being affected by several factors in the current and prospective capital markets, including: the dramatic shifts in market conditions during 2020, the economic recovery in 2021 and the currently high inflation, and the expectations for rising interest rates and continued inflation in 2022, and the effect of these changes on the assumptions used in the ROE estimation models. In this section, I discuss each of these factors and how it affects the models used to estimate the cost of equity for regulated utilities.

A. Economic Recovery and Performance of the Utility Sector

Q. Do recent economic projections indicate the expectation for a continued economic recovery in 2022?

A. Yes. The Federal Open Market Committee ("FOMC") is composed of twelve members including the Board of Governors of the Federal Reserve system and presidents of the Federal Reserve Banks. The FOMC reviews economic and financial conditions, determines the appropriate stance for monetary policy and assess the risks to its long-run goals of price stability and economic growth. The FOMC issued its Summary of Economic Projections in December 2021, where the FOMC's median projection for GDP growth from Q4 2021 to Q4 2022 is 4.0 percent.[4] The Congressional Budget Office ("CBO") issued an update to its outlook on economic conditions on July 1, 2021. In that report, the CBO projected strong GDP growth for 2021 and beyond and significant strength in overall economic conditions including:

- Real GDP growth of 7.4 percent in 2021 and 3.1 percent in 2022, which is a significant change from the negative 2.4 percent growth rate in 2020;
- Inflation indicators at or above the 2.0 percent threshold in 2021 and continuing through 2031;
- Labor force expected to be restored to pre-pandemic levels in 2022; and
- Interest rates on federal borrowing increasing through 2031.[5]

---

[4] Federal Open Market Committee, Summary of Economic Projections at 2 (Dec. 15, 2021).

[5] Congressional Budget Office, An Update to the Budget and Economic Outlook 2021 to 2031, July 2021.

These trends indicate strong economic recovery over the next year, with robust consumer spending expected.

Q. Please summarize the monetary policy actions of the Federal Reserve in response to COVID-19.

A. In response to the COVID-19 pandemic, the Federal Reserve has:

- Decreased the Federal Funds rate twice in March 2020, resulting in a target range of 0.00 percent to 0.25 percent;
- Increased its holdings of both Treasury and mortgaged-back securities;
- Started expansive programs to support credit to large employers – the Primary Market Corporate Credit Facility to provide liquidity for new issuances of corporate bonds; and the Secondary Market Corporate Credit Facility to provide liquidity for outstanding corporate debt issuances; and
- Supported the flow of credit to consumers and businesses through the Term Asset-Backed Securities Loan Facility.

In addition, Congress also passed the Coronavirus Aid, Relief, and Economic Security ("CARES") Act in March 2020, the Consolidated Appropriations Act, 2021 in December 2020 and the American Rescue Plan Act in March 2021, which included $2.2. trillion, $900 billion and $1.9 trillion, respectively, in fiscal stimulus aimed at also mitigating the economic effects of COVID-19. These expansive monetary and fiscal programs mitigated the economic effects of the COVID-19 pandemic and are currently providing additional support as the economy recovers from the COVID-19 recession.

Q. Are there indications the Federal Reserve is ending the accommodative policy tools that were used to support the economy during COVID-19?

A. Yes. Most recently at the December 15, 2021 meeting, in response to inflation exceeding the Federal Reserve's target of 2 percent for a sustained period of time, the Federal Reserve decided to increase the pace of its taper of bond purchases. Beginning in January, the Federal Reserve will reduce asset purchases of Treasuries by $20 billion and mortgage-backed securities by $10 billion on a monthly basis.[6] This change is double the initial plan outlined at the November 2, 2021 meeting which called for reducing asset purchases of Treasuries by $10 billion and mortgage-backed securities by $5 billion on a monthly.[7] Moreover, the Federal Reserves' FOMC is now forecasting three increases in the federal funds rate by the end of 2022[8] which is a substantial increase from the one increase that was forecasted by the FOMC at the September 22, 2021 meeting.[9]

Q. Why has the Federal Reserve decided to normalize monetary policy?

A. The Federal Reserve has accelerated plans to normalize monetary policy in response to increasing inflation. While the Federal Reserve initially viewed inflation as transitory, it has been higher and more persistent than the target levels and is expected to continue in 2022.

---

6 Federal Reserve, Press Release, (Dec. 15, 2021).

7 Federal Reserve, Press Release, (Nov. 3, 2021).

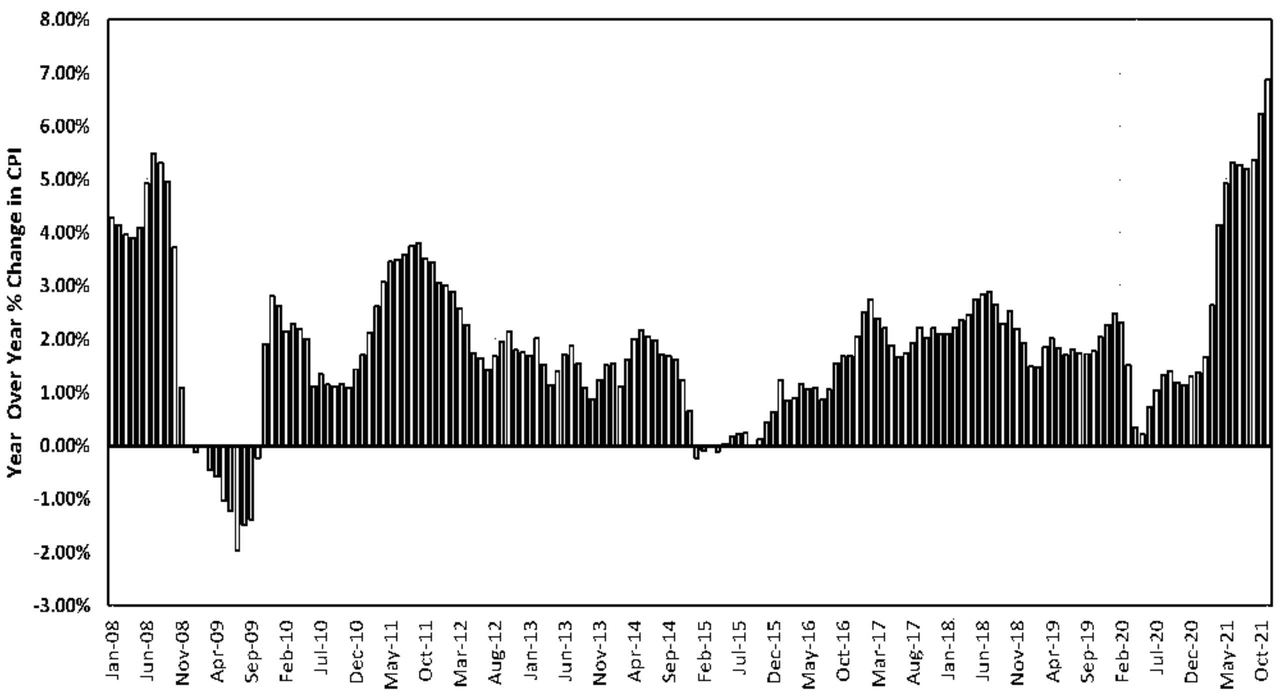
8 Federal Reserve, Summary of Economic Projections, (Dec. 15, 2021).

9 Federal Reserve, Summary of Economic Projections, (Sept. 22, 2021).

Q. How significant is the increase in inflation in 2021?

A. Very significant. As shown in Figure 2, the YOY change in the Consumer Price Index ("CPI") published by the Bureau of Labor statistics has increased steadily in 2021 rising from 1.37 percent in January to 6.88 percent in November. The 6.88 percent YOY in the CPI in November 2021 is the largest 12-month increase since 1982 and is significantly greater than any level seen since January 2008.

Figure 2: Consumer Price Index – YOY Percent Change – January 2008 – November 2021[10]



Q. What are investors' expectations for inflation over the near-term?

A. Investors expect inflation to persist into 2022. For example, Goldman Sachs forecasts consumer price inflation excluding food and energy costs to still be above 4 percent when

---

[10] Source: Bureau of Labor Statistics, shaded area indicates the COVID-19 pandemic recession.

the Federal Reserve ends their tapering of bond purchases in 2022.[11] Similarly, respondents to the recent CNBC Fed Survey, indicated the CPI is expected to rise 3.5 percent in 2022 which is an increase from the September Survey of 3.00 percent.[12] Finally, Kiplinger recently noted the following regarding inflation expectations over the near-term:

> Inflation at the end of next year should be about 2.7%, down from 6.6% at the end of 2021. It's expected that an easing of supply chain shortages next year will bring some price relief, especially to sky-high motor vehicle prices. But, these shortages are expected to only gradually resolve during 2022. Also, worker shortages may last longer than expected, keeping wage growth high and forcing businesses to pass some of those costs on to consumers. So, inflation should remain higher than its 1.7% average over the past ten years.[13]

According to Kiplinger, the higher levels of inflation will likely result in the Federal Reserve increasing the federal funds rate in 2022 instead of 2023 as originally planned.[14]

Q. What effect will inflation have on long-term interest rates?

A. Inflation and the Federal Reserve's normalization of monetary policy will likely result in increases in long-term interest rates. Specifically, inflation reduces the purchasing power of the future interest payments an investor expects to receive over the duration of the bond. This risk increases the longer the duration of the bond. As a result, if investors expect

---

[11] Kennedy, Simon. "Goldman Now Sees Fed Hiking Rates in July as Inflation Lingers." Bloomberg.com, Bloomberg, 30 Oct. 2021, https://www.bloomberg.com/news/articles/2021-10-30/goldman-now-sees-fed-hiking-rates-in-july-as-inflation-lingers.

[12] Liesman, Steve. "Investors Expect a Faster Pace for Fed Rate Hikes, CNBC Survey Shows." CNBC, CNBC, 2 Nov. 2021, https://www.cnbc.com/2021/11/02/investors-expect-a-faster-pace-for-fed-rate-hikes-cnbc-survey-shows.html.

[13] Payne, David, "Inflation hits 30-year High," Kiplinger, November 11, 2021.

[14] Ibid.

increased levels of inflation, they will require higher yields to compensate for the increased risk of inflation which means interest rates will increase.

Q. What have equity analysts said about long-term government bond yields over the near term?

A. Several equity analysts have noted that they expect economic conditions to continue to improve and thus the yields on long-term government bonds to continue to increase through the end of 2022. As shown in Figure 3, according to six different equity analysts, the yield on the 10-year Treasury Bond is expected to range from 1.75 percent to 2.50 percent in 2022 which is 17 to 92 basis points greater than the current 30-day average yield on the 10-year Treasury Bond as of November 30, 2021, of 1.58 percent. Specifically, Morgan Stanley recently noted the following regarding the expectation for long-term government bond yields in 2022:

> Continued strong growth in 2022, alongside receding but above-target inflation, keeps the Fed patient, yet gradually moving toward rate hikes, and keeps Treasury yields moving higher.[15]

Figure 3: Equity Analysts Forecast of the 10-year Treasury Yield[16]

Bank	10-year U.S. Treasury Yield	
	30-day Average as of November 30, 2021	2022 Forecast
Barclays	1.58%	1.75%

[15] "Factbox: Wall Street Forecasts for the U.S. Dollar and 10-Year Treasury Yield in 2022." Reuters, Thomson Reuters, 18 Nov. 2021, https://www.reuters.com/markets/us/wall-street-forecasts-us-dollar-10-year-treasury-yield-2022-2021-11-18/.

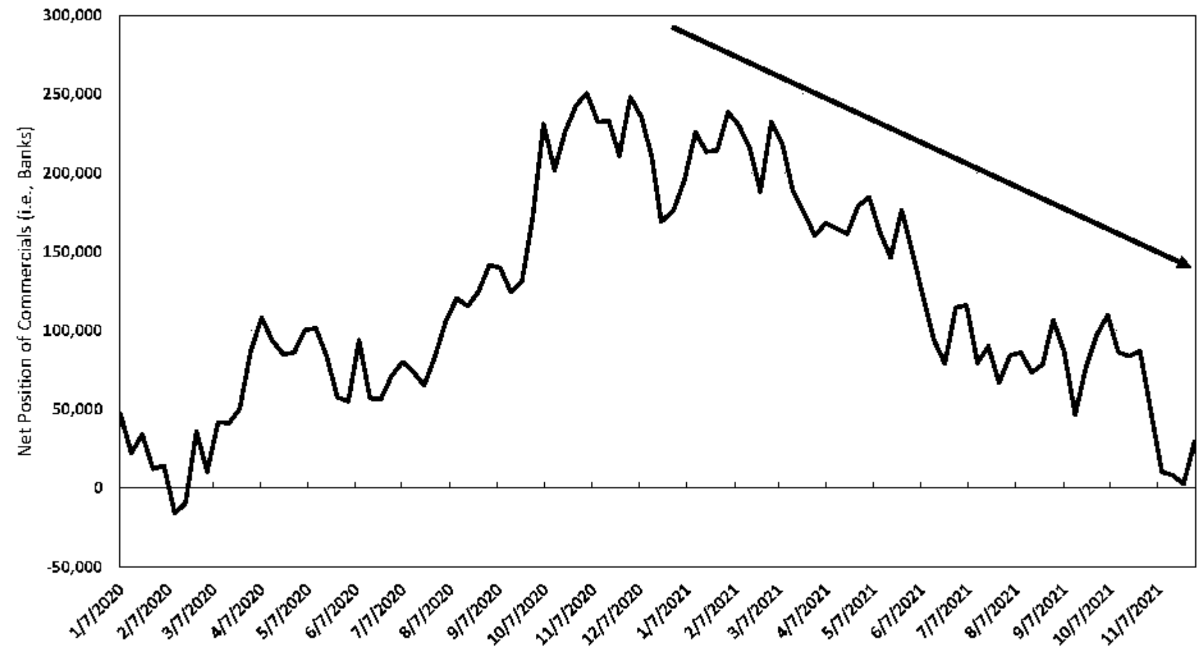
[16] "Factbox: Wall Street Forecasts for the U.S. Dollar and 10-Year Treasury Yield in 2022." Reuters, Thomson Reuters, 18 Nov. 2021, https://www.reuters.com/markets/us/wall-street-forecasts-us-dollar-10-year-treasury-yield-2022-2021-11-18/.

Morgan Stanley	1.58%	2.10%
Goldman Sachs	1.58%	2.00%
JP Morgan	1.58%	2.10%
Wells Fargo Investment Institute	1.58%	2.00% - 2.50%
Amundi	1.58%	1.80% - 2.00%

Q. Have you considered any additional indicators which may imply long-term interest rates are expected to increase?

A. Yes, I have. I considered the net position of commercials (i.e., banks) in U.S. Treasury Bond futures contracts as reported in the Commitment of Traders ("COT") Report produced by the Commodity Futures Trading Commission ("CFTC"). A net position is defined as the total number of long positions in a futures contract minus the total number of short positions in a futures contract. A long position means that an investor agrees to purchase an asset in the future at a specified price today and therefore profits if the price of the underlying asset increases. Conversely, short position is when an investor agrees to sell an asset at a time in the future at a specified price today and profits if the price of the asset declines. Therefore, if banks are increasing the number of short positions and thus have a declining net position, the banks are assuming that the price of the asset will decline. As shown in Figure 4, the net position of banks in U.S. Treasury Bonds has been decreasing since the end of 2020. Therefore, banks are forecasting a decrease in the price of long-term government bonds and thus the yields (which are inversely related to the price) to increase over the near-term.

Figure 4: Commitment of Traders Report – Net Position of Commercials (i.e., Banks) in U.S. Treasury Bond Futures Contracts[17]



Q. Are utility share prices correlated to changes in the yields on long-term government bonds?

A. Yes, interest rates and utility share prices are inversely correlated which means, for example, that an increase in interest rates will result in a decline in the share prices of utilities. For example, Goldman Sachs and Deutsche Bank recently examined the sensitivity of share prices of different industries to changes in interest rates over the past five years. Both Goldman Sachs and Deutsche Bank found that utilities had one of the strongest negative relationships with bond yields (i.e., increases in bond yields resulted in the decline of utility share prices).[18] Charles Schwab also recently noted the inverse

---

[17] Commitment of Traders Report, as of November 30, 2021 - https://www.cftc.gov/MarketReports/CommitmentsofTraders/HistoricalCompressed/index.htm

[18] Lee, Justina. "Wall Street Is Rethinking the Treasury Threat to Big Tech Stocks." Bloomberg.com, 11 Mar. 2021, www.bloomberg.com/news/articles/2021-03-11/wall-street-is-rethinking-the-treasury-threat-to-big-tech-stocks.

relationship between interest rates and utility share prices and concluded that the utility sector tends to underperform during periods of economic growth when interest rates are higher.[19]

Q. How do equity analysts expect the utilities sector to perform in an increasing interest rate environment?

A. Equity analysts project that utilities are expected to continue to underperform the broader market as interest rates increase. For example, in a recent article, Barron's conducted its Big Money poll of professional investors regarding the outlook for the next twelve months. Approximately 60 percent of respondents projected the yield on the 10-year Treasury Bond will be 2.00 percent or greater at the end of the next twelve months which is an increase from the current 30-day average 10-year Treasury Bond yield as of November 30, 2021 of 1.58 percent.[20] Furthermore, the professional investors surveyed by Barron's selected the utility sector as the sector which will perform the worst over the next twelve months indicating they are projecting that utilities will underperform the broader market in 2022.

Other equity analysts concur with this conclusion. Fidelity recently recommended underweighting the utility sector and noted that "[w]eak fundamentals and high valuations could be headwinds for utilities and real estate, especially if rates increase."[21] In its 2022 Outlook, Well Fargo classified the utility sector as "most unfavorable" as economic growth

---

[19] Charles Schwab, Schwab Sector Views: Too Early for Defensive Positioning, August 19, 2021.

[20] Jasinski, Nicholas. Stocks Are Still the Place to Be, Our Exclusive Big Money Poll Finds. Barron's, 16 Oct. 2021, https://www.barrons.com/articles/stock-market-covid-economy-outlook-51634312012?mod=hpsubnav&tesla=y.

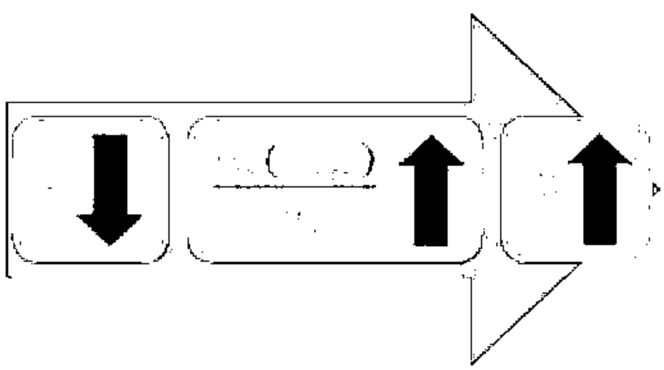
[21] Fidelity, "Q4 2021 sector scorecard," October 27, 2021.

continues to rebound and interest rates increase.[22] Finally, Charles Schwab has classified the utilities sector overall as "Underperform," noting negatives for the sector that include "interest rates are expected to recover from recent decline" and "economic recovery makes the sector less attractive, relative to other sectors".[23]

Q. What is the significance of the inverse relationship between interest rates and utility share prices in the current market?

A. As discussed above, the economy is currently in the recovery phase of the business cycle, which is characterized by improving economic growth, increasing inflation, and increasing interest rates. If interest rates increase as expected, then the share prices of utilities will decline. If the prices of utility stocks decline, then the DCF model, which relies on historical averages of share prices, is likely to understate the cost of equity. For example, Figure 5, below summarizes the effect of price on the dividend yield in the Constant Growth DCF model.

Figure 5: The Effect of a decline in Stock Prices on the Constant Growth DCF model



[22] Well Fargo Investment Institute, 2022 Outlook, December 2021.

[23] Charles Schwab, "Utilities Sector Rating: Underperform," November 18, 2021.

A decline in stock prices will increase the dividend yields and thus the estimate of the ROE produced by the Constant Growth DCF model. Therefore, this expected change in market conditions supports consideration of the range of ROE results produced by the mean to mean-high DCF results since the mean DCF results would likely understate the cost of equity during the period that the Company's rates will be in effect. Moreover, prospective market conditions warrant consideration of other ROE estimation models such as the CAPM, ECAPM, and Risk Premium which may better reflect expected market conditions. For example, two out of three inputs to the CAPM (i.e., the market risk premium and risk-free rate) are forward-looking.

B. Conclusion

Q. What are your conclusions regarding the effect of current market conditions on the cost of equity for the Company?

A. Over the near-term, investors expect economic growth to continue to rebound and thus inflation and interest rates to increase. Because the share prices of utilities are inversely correlated to the interest rates, an increase in long-term government bond yields will likely results in a decline in utility share prices which is the reason a number of equity analysts expect the utility sector to underperform over the near-term. The expected underperformance of utilities means that DCF models using recent historical data likely underestimate investors' required return over the period that rates will be in effect. This change in market conditions also supports the use of other ROE estimation models such as the CAPM, ECAPM, and Risk Premium which may better reflect expected market conditions.

IV. PROXY GROUP SELECTION

Q. Please provide a brief profile of MidAmerican.

A. MidAmerican is a wholly owned indirect subsidiary of Berkshire Hathaway Energy Company. The Company provides regulated retail electric service to approximately 800,000 customers in portions of Iowa, Illinois and South Dakota and retail and transportation of natural gas to approximately 800,000 customers in Iowa, Illinois, Nebraska and South Dakota.[24] MidAmerican is currently rated A/Stable by Standard & Poor's and A1/Stable by Moody's.[25]

Q. Why have you used a group of proxy companies to estimate the cost of equity for MidAmerican?

A. In this proceeding, we focus on estimating the cost of equity for an electric utility company that is not itself publicly traded. Because the cost of equity is a market-based concept and because MidAmerican's operations do not make up the entirety of a publicly traded entity, it is necessary to establish a group of companies that is both publicly traded and comparable to the Company in certain fundamental business and financial respects to serve as its "proxy" in the ROE estimation process.

Even if MidAmerican was a publicly traded entity, it is possible that transitory events could bias its market value over a given period. A significant benefit of using a proxy group is

[24] S&P Global Market Intelligence.

[25] Source: S&P Capital IQ Pro, (December 6, 2021).

that it moderates the effects of unusual events that may be associated with any one company. The proxy companies used in my analyses all possess a set of operating and risk characteristics that are substantially comparable to the Company, and thus provide a reasonable basis to derive and estimate the appropriate ROE for MidAmerican.

Q. How did you select the companies included in your proxy group?

A. I began with the group of 36 companies that Value Line classifies as Electric Utilities and applied the following screening criteria to select companies that:

- Pay consistent quarterly cash dividends, because companies that do not pay a dividend cannot be analyzed using the Constant Growth DCF model;
- Have investment grade long-term issuer ratings from S&P and/or Moody's;
- Are covered by at least two utility industry analysts;
- Have positive long-term earnings growth forecasts from at least two utility industry equity analysts;
- Own regulated generation assets that are included in rate base;
- Derive more than 40 percent of its megawatt-hour sales from its owned generation facilities;
- Derive more than 60 percent of their total operating income from regulated operations;
- Derive more than 60 percent of their total regulated operating income from regulated electric operations; and
- Were not parties to a merger or transformative transaction during the analytical periods relied on.

Q. Did you exclude any other companies from the proxy group?

A. Yes. I also excluded Pinnacle West Capital Corporation ("PNW") and Hawaiian Electric Industries, Inc ("HE") from my proxy group. PNW was excluded from my proxy group because its stock price has recently been affected by a one-time event which is similar to the reason that I exclude transformative transactions. The stock price of Pinnacle West Capital decreased approximately 24 percent from August 2021 through November 2021 resulting from a negative regulatory decision for its largest operating company, Arizona Public Service Company. Therefore, I have excluded this company from the proxy group. Additionally, I excluded HE from the proxy group due to the fact that its business and financial risk is generally different from MidAmerican. HE's operations are concentrated on the islands of Hawaii; therefore, the company faces geographic concentration risk. As HE noted in the company's 2020 Form 10-K:

> [t]he Company is subject to the risks associated with the geographic concentration of its businesses and current lack of interconnections that could result in service interruptions at the Utilities or higher default rates on loans held by ASB [American Savings Bank.[26]

The increased risk of service interruptions resulting from HE's geographic location which could result in revenue loss and increased costs is a risk unique to HE and would not apply to utilities located on the U.S. mainland. Furthermore, HE's unregulated operations which represent approximately 20 percent of the company's operating income in 2020 are concentrated in the banking sector through the ownership of American Savings Bank

[26] Hawaii Electric Industries, Inc., 2020 Form 10-K, at 20.

("ASB").[27] ASB also only operates on Hawaii; thus, all of the company's consumer and commercial loans are to customers on Hawaii. If Hawaii were to face an adverse economic or political event, ASB could face severe financial effects given the company's geographic concentration in Hawaii.[28] As a result, I have excluded HE from my proxy group considering HE's unique geographical risks.

Q. What is the composition of your proxy group?

A. The screening criteria discussed above are shown in MidAmerican Bulkley Direct Exhibit-ROE, Schedule 2 and resulted in a proxy group consisting of the companies shown in Figure 6 below.

[27] *Id.*, 84.

[28] *Id.*, at 20.

Figure 6: Proxy Group

Company	Ticker
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Avista Corporation	AVA
Duke Energy Corporation	DUK
Entergy Corporation	ETR
Evergy, Inc.	EVRG
IDACORP, Inc.	IDA
MGE Energy, Inc.	MGEE
NextEra Energy, Inc.	NEE
NorthWestern Corporation	NWE
Otter Tail Corporation	OTTR
Portland General Electric Company	POR
Southern Company	SO
Xcel Energy Inc.	XEL

V. COST OF EQUITY ESTIMATION

Q. Please briefly discuss the ROE in the context of the regulated rate of return ("ROR").

A. The ROE is the cost rate applied to the equity capital in the ROR. The ROR for a regulated utility is the weighted average cost of capital, in which the cost rates of the individual sources of capital are weighted by their respective book values. While the costs of debt and preferred stock can be directly observed, the cost of equity is market-based and, therefore, must be estimated based on observable market data.

Q. How is the required ROE determined?

A. The required ROE is estimated by using one or more analytical techniques that rely on market-based data to quantify investor expectations regarding equity returns, adjusted for certain incremental costs and risks. Informed judgment is then applied to determine where the company's cost of equity falls within the range of results. The key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general, as well as the subject company (in the context of the proxy group), in particular.

Q. What methods did you use to estimate the base ROE?

A. I considered the results of the Constant Growth DCF model, the CAPM, the ECAPM, and a Bond Yield Plus Risk Premium analysis. As discussed in more detail below, a reasonable ROE estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results.

A. Importance of Multiple Analytical Approaches

Q. Why is it important to use more than one analytical approach?

A. Because the cost of equity is not directly observable, it must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the cost of equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed. Several models have been developed to estimate the cost of equity, and I use multiple approaches to estimate the cost of equity. As a practical matter, however, all the models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints. Consequently, many wellregarded finance texts recommend using multiple approaches when estimating the cost of equity. For example, Copeland, Koller, and Murrin[29] suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski[30] recommend the CAPM, DCF, and Bond Yield Plus Risk Premium approaches.

Q. Do current market conditions increase the importance of using more than one analytical approach?

A. Yes. Low interest rates and the effects of the investor "flight to quality" can be seen in high utility share valuations, relative to historical levels and relative to the broader market. Higher utility stock valuations produce lower dividend yields and result in lower cost of equity estimates from a DCF analysis. Low interest rates also affect the CAPM in two ways: (1) the risk-free rate is lower, and (2) because the market risk premium is a function of interest rates, (i.e., it is the return on the broad stock market less the risk-free interest rate), the risk premium should move higher when interest rates are lower. Therefore, it is important to use multiple analytical approaches to moderate the impact that the current low interest rate environment is having on the ROE estimates for the proxy group and, where possible, consider using projected market data in the models to estimate the return for the forward-looking period.

---

[29] Tom Copeland, Tim Koller and Jack Murrin, Valuation: Measuring and Managing the Value of Companies, 3rd Ed. (New York: McKinsey & Company, Inc., 2000), at 214.

[30] Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed. (Orlando: Dryden Press, 1994), at 341.

Q. Has the Board made similar findings regarding the reliance on multiple models?

A. Yes. In a 2014 decision for MidAmerican, the Board noted that the various models presented produce a range for the Board to consider. Further, the Board noted that there is no precise return on equity that is accurate or only one that is appropriate, but a range of reasonable returns. Within that range, the Board determines the most appropriate return, balancing the interests of shareholders and ratepayers. Further, the Board noted that it normally considers the DCF, risk premium and CAPM in determining the appropriate ROE.[31]

Q. Are you aware of any other regulatory commissions that have recognized the importance of considering the results of multiple models?

A. Yes, several regulatory commissions consider the results of multiple ROE estimation methodologies such as the DCF, CAPM, ECAPM and Risk Premium in determining the authorized ROE, including the Minnesota Public Utilities Commission ("Minnesota PUC")[32], the Michigan Public Service Commission ("Michigan PSC")[33], the Washington Utilities and Transportation Commission ("Washington UTC"),[34] and the New Jersey Board of Public Utilities ("NJBPU").[35] For example, the Washington UTC has repeatedly

[31] State of Iowa Department of Commerce Utilities Board, In Re: MidAmerican Energy Company, Docket No. RPU-2013-0004, Order Approving Settlement, With Modifications, and Requiring Additional Information, March 17, 2014, at 20-23.

[32] Docket No. G011/GR-17-563, Findings of Fact, Conclusions and Order, at 27; Docket No. E015/GR-16-664, Findings of Fact, Conclusions and Order, at 60-61

[33] Michigan Public Service Commission Order, DTE Gas Company, Case No. U-18999, at 45-47 (Sept. 13, 2018).

[34] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-130043, Order 05, n. 89 (Dec. 4, 2013); *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-100749, Order 06, ¶ 91 (March 25, 2011).

[35] NJBPU Docket No. ER12111052, OAL Docket No. PUC16310-12, Order Adopting Initial Decision with Modifications and Clarifications, at 71 (March 18, 2015).

emphasized that it "places value on each of the methodologies used to calculate the cost of equity and does not find it appropriate to select a single method as being the most accurate or instructive."[36] The Washington UTC has also explained that "[f]inancial circumstances are constantly shifting and changing, and we welcome a robust and diverse record of evidence based on a variety of analytics and cost of capital methodologies."[37]

Additionally, in its recent order for DTE Gas Company ("DTE Gas") in Case No. U-18999, the Michigan PSC considered the results of each of the models presented by the ROE witnesses which included the DCF, CAPM, ECAPM and Risk Premium in the determination of the authorized ROE.[38] The Commission also considered authorized ROEs in other states, increased volatility in capital markets and the company-specific business risks of DTE Gas.

Q. What are your conclusions about the results of the DCF and CAPM models?

A. Recent market data that is used as the basis for the assumptions for both models have been affected by market conditions. As a result, relying exclusively on historical assumptions in these models, without considering whether these assumptions are consistent with investors' future expectations, will underestimate the cost of equity that investors would require over the period that the rates in this case are to be in effect. In this instance, relying on the historically low dividend yields that are not expected to continue over the period that the new rates will be in effect will underestimate the ROE for MidAmerican.

---

[36] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-130043, Order 05, n. 89 (Dec. 4, 2013).

[37] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-100749, Order 06, ¶ 91 (March 25, 2011).

[38] Michigan Public Service Commission Order, DTE Gas Company, Case No. U-18999, at 45-47 (Sept. 13, 2018).

Furthermore, as discussed in Section III above, long-term interest rates have increased since August 2020 and this trend is expected to continue over the near-term as the economy enters the recovery phase of the business cycle. Therefore, the use of current averages of Treasury bond yields as the estimate of the risk-free rate in the CAPM is not appropriate since recent market conditions are not expected to continue over the long-term. Instead, analysts should rely on projected yields of Treasury Bonds in the CAPM. The projected Treasury Bond yields results in CAPM estimates that are more reflective of the market conditions that investors expect during the period that the Company's rates will be in effect.

B. Constant Growth DCF Model

Q. Please describe the DCF approach.

A. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_\infty}{(1+k)^\infty} \qquad [1]$$

Where P_0 represents the current stock price, $D_1 \ldots D_\infty$ are all expected future dividends, and k is the discount rate, or required ROE. Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

$$k = \frac{D_0(1+g)}{P_0} + g \qquad [2]$$

Equation [2] is often referred to as the Constant Growth DCF model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Q. What assumptions are required for the Constant Growth DCF model?

A. The Constant Growth DCF model requires the following four assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings ratio; and (4) a discount rate greater than the expected growth rate. To the extent that any of these assumptions are violated, considered judgment and/or specific adjustments should be applied to the results.

Q. What market data did you use to calculate the dividend yield in your Constant Growth DCF model?

A. The dividend yield in my Constant Growth DCF model is based on the proxy companies' current annualized dividend and average closing stock prices over the 30-, 90-, and 180-trading days ended November 30, 2021.

Q. Why did you use 30-, 90-, and 180-day averaging periods?

A. In my Constant Growth DCF model, I use an average of recent trading days to calculate the term P_0 in the DCF model to ensure that the ROE is not skewed by anomalous events that may affect stock prices on any given trading day. The averaging period should also be reasonably representative of expected capital market conditions over the long term. However, the averaging periods that I use rely on historical data that are not consistent with the forward-looking market expectations. Therefore, the results of my Constant Growth DCF model using historical data may underestimate the forward-looking cost of equity. As a result, I place more weight on the mean to mean-high results produced by my Constant Growth DCF model.

Q. Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A. Yes, I did. Because utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth rate for purposes of calculating the expected dividend yield component of the DCF model. This adjustment ensures that the expected first-year dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the aggregated dividends to be paid during that time.

Q. Why is it important to select appropriate measures of long-term growth in applying the DCF model?

A. In its Constant Growth form, the DCF model (*i.e.*, Equation [2]) assumes a single growth estimate in perpetuity. To reduce the long-term growth rate to a single measure, one must assume that the payout ratio remains constant and that earnings per share, dividends per share and book value per share all grow at the same constant rate. Over the long run, however, dividend growth can only be sustained by earnings growth. Therefore, it is important to incorporate a variety of sources of long-term earnings growth rates into the Constant Growth DCF model.

Q. Which sources of long-term earnings growth rates did you use?

A. My Constant Growth DCF model incorporates three sources of long-term earnings growth rates: (1) Zacks Investment Research; (2) Yahoo! Finance; and (3) Value Line Investment Survey.

Q. How did you calculate the range of results for the Constant Growth DCF Models?

A. I calculated the low result for my DCF model using the minimum growth rate (*i.e.*, the lowest of the Value Line, Yahoo! Finance, and Zacks earnings growth rates) for each of the proxy group companies. Thus, the low result reflects the minimum DCF result for the proxy group. I used a similar approach to calculate the high results, using the highest growth rate for each proxy group company. The mean results were calculated using the average growth rates from all sources.

Q. Did you review the DCF results for individual companies in your proxy group?

A. Yes, I did. It is important to review the DCF results of the individual companies included in the proxy to ensure that the DCF results of each company provide a sufficient return increment above the long-term debt costs to compensate investors for the added risk of an equity investment.

Q. How did you determine the low-end threshold that would be used to evaluate the DCF results for the individual companies in your proxy group?

A. The average credit rating for the companies in my proxy group is BBB+ from S&P and Baa1 from Moody's. The average yield on Moody's Baa-rated utility bonds for the 30 trading days ending November 30, 2021, was 3.27 percent.[39] Therefore, for example, a 7.00 percent DCF result would only provide a risk premium of 373 basis points above Baa-rated utility bonds. As a result, I have determined that a Constant Growth DCF result lower

[39] The yield on the Moody's Baa-rated utility bonds was obtained from Bloomberg Professional (Dec. 1, 2021). The Moody's Baa-rated utility bond index includes bonds with credit ratings of Baa1, Baa2 and Baa3. There is currently not an index that is composed entirely of Baa1 bonds.

than 7.00 percent would not provide equity investors a sufficient risk premium above long-term debt costs.

Q. How did you address the DCF results for individual companies in your proxy group that were below 7 percent?

A. I developed two approaches to account for the DCF results for individual companies in my proxy group that were below 7 percent. In the first approach, I excluded the DCF results that were below 7 percent and then calculated the mean DCF result for the proxy group. Since the mean can be affected by outlier results, it is important to exclude the individual results for companies that would not provide a sufficient return requirement above long-term debt costs. In the second approach, I relied on the median DCF result for the proxy group as opposed to the mean and did not exclude any DCF results for individual companies. In general, the median is not affected to a large degree by the presence of outliers and thus can be applied when it is determined that a data may include outliers.

Q. What were the results of your Constant Growth DCF analyses?

A. Figure 7 (see also MidAmerican Bulkley Direct Exhibit-ROE, Schedule 3) summarizes the results of my DCF analyses. As shown in Figure 7, the median and mean DCF results range from 9.36 percent to 9.61 percent, and the median high and mean high results are in the range of 10.22 percent to 10.46 percent. While I also summarize the low DCF results, given the expected underperformance of utility stocks and thus the likelihood that the DCF model is understating the cost of equity, I do not believe it is appropriate to consider the low DCF results at this time.

Figure 7: Constant Growth Discounted Cash Flow Results

Constant Growth DCF - Median			
	Median Low	**Median**	**Median High**
30-Day Average	8.83%	9.54%	10.46%
90-Day Average	8.78%	9.61%	10.36%
180-Day Average	8.80%	9.54%	10.25%
Constant Growth DCF - Average w/ Exclusions			
	Mean Low	**Mean**	**Mean High**
30-Day Average	8.73%	9.40%	10.26%
90-Day Average	8.69%	9.36%	10.22%
180-Day Average	8.83%	9.37%	10.23%

Q. What are your conclusions about the results of the DCF models?

A. As discussed previously, one primary assumption of the Constant Growth DCF model is a constant P/E ratio. That assumption is heavily influenced by the market price of utility stocks. Since utility stocks are expected to underperform the broader market over the near-term as interest rates increases, it is important to consider the results of the DCF models with caution. This means that the results of the current DCF models are below where they would otherwise be under more normal market conditions. Therefore, while I have given weight to the results of the Constant Growth DCF model, my recommendation also gives weight to the results of other ROE estimation models.

C. CAPM Analysis

Q. Please briefly describe the CAPM.

A. The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable, systematic risk of that security. Systematic risk is the risk inherent in the entire market or market segment—which cannot be diversified away using a portfolio of assets. Unsystematic risk is the risk of a specific company that can, theoretically, be mitigated through portfolio diversification.

The CAPM is defined by four components, each of which must theoretically be a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) \quad [3]$$

Where:

K_e = the required market ROE;

β = Beta coefficient of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market.

In this specification, the term (r_m – r_f) represents the market risk premium. According to the theory underlying the CAPM, because unsystematic risk can be diversified away, investors should only be concerned with systematic or non-diversifiable risk. Systematic risk is measured by Beta. Beta is a measure of the volatility of a security as compared to the market as a whole. Beta is defined a:

$$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)} \quad [4]$$

The variance of the market return (i.e., Variance (r_m)) is a measure of the uncertainty of the general market, and the covariance between the return on a specific security and the general market (i.e., Covariance (r_e, r_m)) reflects the extent to which the return on that security will respond to a given change in the general market return. Thus, Beta represents the risk of the security relative to the general market.

Q. What risk-free rate did you use in your CAPM analysis?

A. I relied on three sources for my estimate of the risk-free rate: (1) the current 30-day average yield on 30-year U.S. Treasury bonds, which is 1.97 percent;[40] (2) the average projected 30-year U.S. Treasury bond yield for the first quarter of 2022 through the first quarter of 2023, which is 2.46 percent;[41] and (3) the average projected 30-year U.S. Treasury bond yield for 2023 through 2027, which is 3.40 percent.[42]

Q. Would you place more weight on one of these scenarios?

A. Yes. Based on current market conditions, I place more weight on the results of the projected yields on the 30-year Treasury bonds. As discussed previously, the estimation of the cost of equity in this case should be forward-looking because it is the return that investors would receive over the future rate period. Therefore, the inputs and assumptions used in the CAPM analysis should reflect the expectations of the market at that time. While I have included the results of a CAPM analysis that relies on the current average risk-free rate, this analysis fails to take into consideration the effect of the market's expectations for interest rate increases on the cost of equity.

Q. What Beta coefficients did you use in your CAPM analysis?

A. As shown in MidAmerican Bulkley Direct Exhibit-ROE, Schedule 4, I used the Beta coefficients for the proxy group companies as reported by Bloomberg and Value Line. The Beta coefficients reported by Bloomberg were calculated using ten years of weekly returns

---

40 Bloomberg Professional as of November 30, 2021.

41 Blue Chip Financial Forecasts, Vol. 40, No. 12, at 2 (December 1, 2021).

42 Blue Chip Financial Forecasts, Vol. 40, No. 12, at 14 (December 1, 2021).

relative to the S&P 500 Index. Value Line's calculation is based on five years of weekly returns relative to the New York Stock Exchange Composite Index.

Additionally, as shown in MidAmerican Bulkley Direct Exhibit-ROE, Schedule 4, I also considered an additional CAPM analysis which relies on the long-term average utility Beta coefficient for the companies in my proxy group. As shown in MidAmerican Bulkley Direct Exhibit-ROE, Schedule 5, the long-term average utility Beta coefficient was calculated as an average of the Value Line Beta coefficients for the companies in my proxy group from 2011 through 2020.

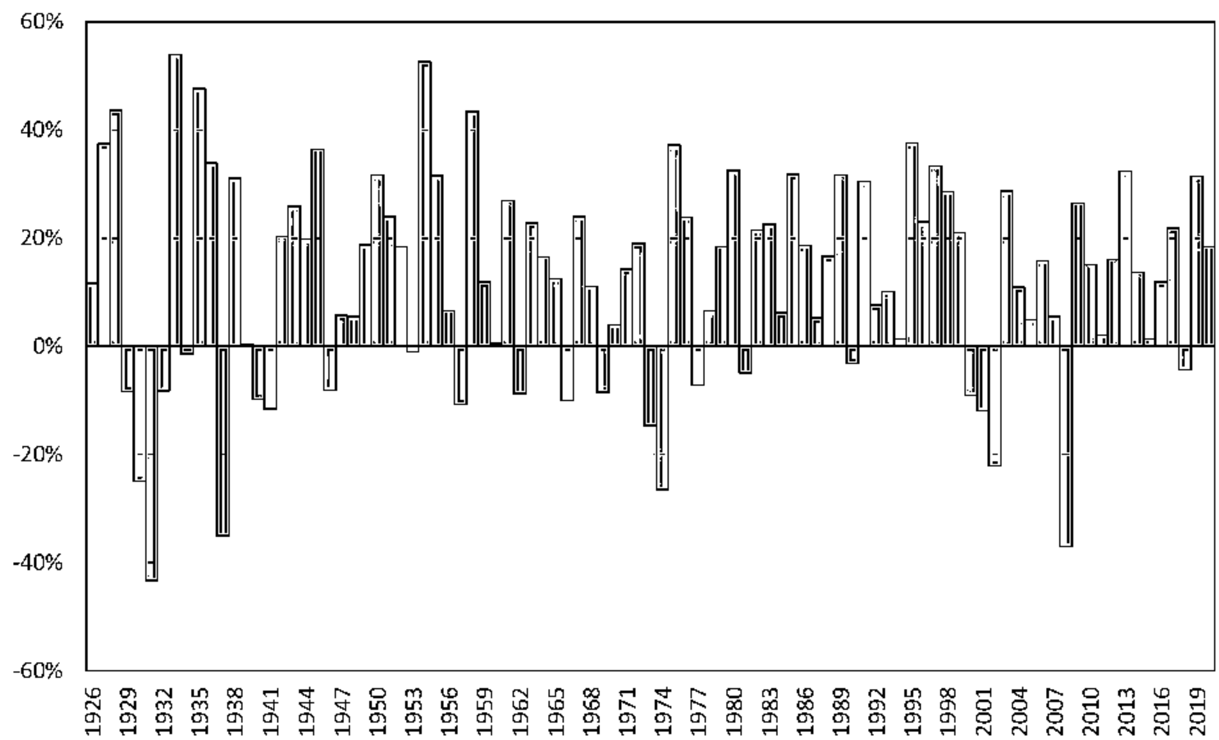
Q. How did you estimate the market risk premium in the CAPM?

A. I estimated the Market Risk Premium ("MRP") as the difference between the implied expected equity market return and the risk-free rate. As shown in MidAmerican Bulkley Direct Exhibit-ROE, Schedule 6, the expected return on the S&P 500 Index is calculated using the Constant Growth DCF model discussed earlier in my testimony for the companies in the S&P 500 Index. In my calculation of the market return, I included companies in the S&P 500 that: 1) had ether a dividend yield or Value Line long-term earnings projections; and 2) had a Value Line long-term earnings growth rate that was greater than 0 percent and less than or equal to 20 percent. Based on an estimated market capitalization-weighted dividend yield of 1.58 percent and a weighted long-term growth rate of 11.31 percent, the estimated required market return for the S&P 500 Index is 12.97 percent.

Q. How does the current expected market return of 12.97 percent compare to observed historical market returns?

A. Given the range of annual equity returns that have been observed over the past century (shown in Figure 8), a current expected return of 12.97 percent is not unreasonable. In 49 out of the past 95 years (or roughly 52 percent of observations), the realized equity return was at least 12.97 percent or greater.

Figure 8: Realized U.S. equity market returns (1926-2020) [43]



Q. Did you consider another form of the CAPM in your analysis?

A. Yes. I have also considered the results of an ECAPM or alternatively referred to as the Zero-Beta CAPM[44] in estimating the cost of equity for MidAmerican. The ECAPM

[43] Depicts total annual returns on large company stocks, as reported in the 2021 Duff and Phelps SBBI Yearbook.

[44] *See* Roger A. Morin, New Regulatory Finance at 189, Public Utilities Reports, Inc. (2006).

calculates the product of the adjusted Beta coefficient and the market risk premium and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the market risk premium, without any effect from the Beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [5] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad [5]$$

Where:

k_e – the required market ROE;

β – Adjusted Beta coefficient of an individual security;

rf – the risk-free rate of return; and

r_m = the required return on the market as a whole.

In essence, the Empirical form of the CAPM addresses the tendency of the "traditional" CAPM to underestimate the cost of equity for companies with low Beta coefficients such as regulated utilities. In that regard, the ECAPM is not redundant to the use of adjusted Betas; rather, it recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, and that the CAPM underestimates the "alpha," or the constant return term.[45]

---

[45] *Id.*, at 191.

As with the CAPM, my application of the ECAPM uses the forward-looking market risk premium estimates, the three yields on 30-year Treasury securities noted earlier as the risk-free rate, and the Bloomberg, Value Line, and long-term average Beta coefficients.

Q. What are the results of your CAPM analyses?

A. As shown in Figure 9 (see also MidAmerican Bulkley Direct Exhibit-ROE, Schedule 4), my traditional CAPM analysis produces a range of returns from 9.84 percent to 11.80 percent. The ECAPM analysis results range from 10.63 percent to 12.09 percent.

Figure 92: CAPM Results

	Current Risk-Free Rate (1.97%)	**Q1 2022 – Q1 2023 Projected Risk-Free Rate (2.46%)**	**2023-2027 Projected Risk-Free Rate (3.40%)**
CAPM			
Value Line Beta	11.63%	11.69%	11.80%
Bloomberg Beta	10.85%	10.94%	11.12%
Long-term Avg. Beta	9.84%	9.98%	10.25%
ECAPM			
Value Line Beta	11.96%	12.01%	12.09%
Bloomberg Beta	11.38%	11.45%	11.58%
Long-term Avg. Beta	10.63%	10.73%	10.93%

D. Bond Yield Plus Risk Premium Analysis

Q. Please describe the Bond Yield Plus Risk Premium approach.

A. In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as a bondholder. That is, because returns to equity holders have greater risk than returns to bondholders, equity investors must be compensated to bear that risk. Risk premium approaches, therefore, estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. In my analysis, I used actual authorized returns for electric utility companies as the historical measure of the cost of equity to determine the risk premium.

Q. Are there other considerations that should be addressed in conducting this analysis?

A. Yes, there are. It is important to recognize both academic literature and market evidence indicating that the equity risk premium (as used in this approach) is inversely related to the level of interest rates. That is, as interest rates increase, the equity risk premium decreases, and vice versa. Consequently, it is important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and (2) relies on recent and expected market conditions. Such an analysis can be developed based on a regression of the risk premium as a function of U.S. Treasury bond yields. If we let authorized ROEs for electric utilities serve as the measure of required equity returns and define the yield on the long-term U.S. Treasury bond as the relevant measure of interest rates, the risk premium simply would be the difference between those two points.[46]

Q. Is the Bond Yield Plus Risk Premium analysis relevant to investors?

A. Yes, it is. Investors are aware of ROE awards in other jurisdictions, and they consider those awards as a benchmark for a reasonable level of equity returns for utilities of comparable risk operating in other jurisdictions. Because my Bond Yield Plus Risk

46 *See* S. Keith Berry, Interest Rate Risk and Utility Risk Premia during 1982-93, Managerial and Decision Economics, Vol. 19, No. 2 (March, 1998), in which the author used a methodology similar to the regression approach described below, including using allowed ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates. *See also* Robert S. Harris, Using Analysts' Growth Forecasts to Estimate Shareholders Required Rates of Return at 66, Financial Management (Spring 1986).

Premium analysis is based on authorized ROEs for utility companies relative to corresponding Treasury yields, it provides relevant information to assess the return expectations of investors.

Q. What did your Bond Yield Plus Risk Premium analysis reveal?

A. As shown in Figure 10 below, from 1992 through November 2021, there was a strong negative relationship between risk premia and interest rates. To estimate that relationship, I conducted a regression analysis using the following equation:

$$RP = a + b(T) \quad [6]$$

Where:

RP = Risk Premium (difference between allowed ROEs and the yield on 30-year U.S. Treasury bonds)

a = intercept term

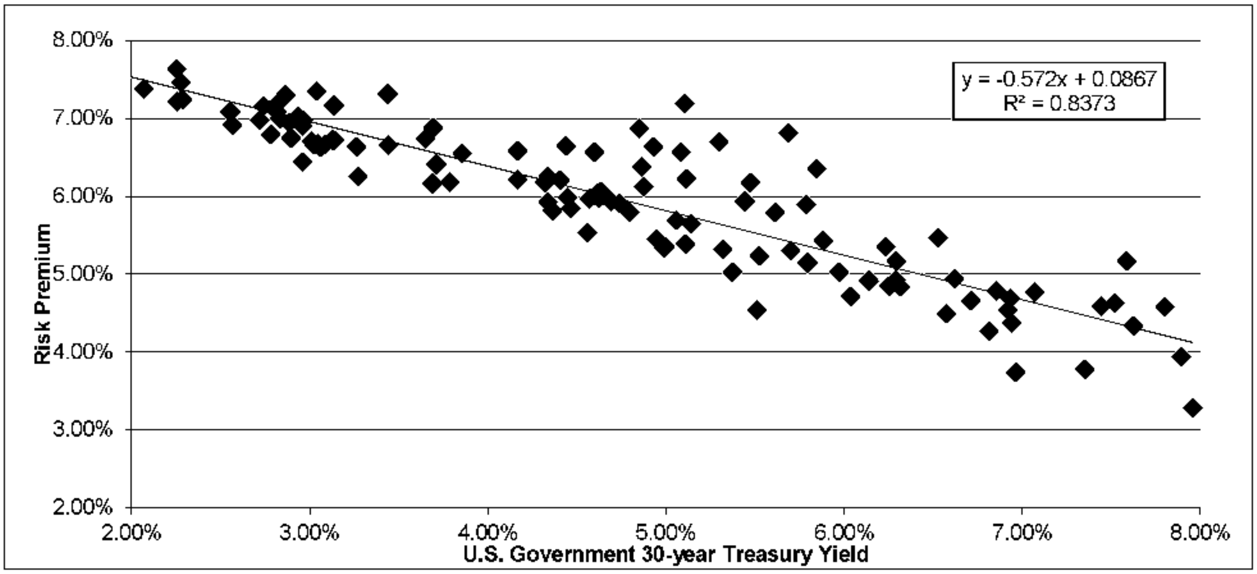
b = slope term

T = 30-year U.S. Treasury bond yield

Data regarding allowed ROEs were derived from all of the vertically integrated electric utility rate cases from 1992 through November 2021 as reported by Regulatory Research Associates ("RRA").[47] This equation's coefficients were statistically significant at the 99.00 percent level.

[47] My analysis began with a total of 1,343 electric utility cases, which were screened to eliminate limited issue rider cases, transmission cases, distribution only cases, and cases that did not specify an authorized ROE. After applying those screening criteria, the analysis was based on data for 675 cases.

Figure 3: Risk Premium Results



As shown in MidAmerican Bulkley Direct Exhibit-ROE, Schedule 7, based on the current 30-day average of the 30-year U.S. Treasury bond yield (i.e., 1.97 percent), the risk premium would be 7.55 percent, resulting in an estimated ROE of 9.52 percent. Based on the near-term (Q1 2022 – Q1 2023) projections of the 30-year U.S. Treasury bond yield (i.e., 2.46 percent), the risk premium would be 7.27 percent, resulting in an estimated ROE of 9.73 percent. Based on longer-term (2023 – 2027) projections of the 30-year U.S. Treasury bond yield (i.e., 3.40 percent), the risk premium would be 6.73 percent, resulting in an estimated ROE of 10.13 percent.

Q. How did the results of the Bond Yield Risk Premium inform your recommended ROE for MidAmerican?

A. I have considered the results of the Bond Yield Risk Premium analysis in setting my recommended ROE for MidAmerican. As noted above, investors consider the ROE award of a company when assessing the risk of that company as compared to utilities of comparable risk operating in other jurisdictions. The Risk Premium analysis considers this comparison by estimating the return expectations of investors based on the current and past ROE awards of electric utilities across the U.S.

VI. INCREMENTAL RISK RELATED TO Wind PRIME

Q. Do the DCF, CAPM and ECAPM results for the proxy group, taken alone, provide an appropriate estimate of the cost of equity for MidAmerican for this project?

A. No. The range of results provided from the ROE estimation methodologies rely on current and short-term projected market data and are therefore intended to reflect the cost of equity over a similar time-period. In this proceeding, MidAmerican is seeking advance ratemaking principles for assets that will be in service for a period of 30 to 40 years. The advance ratemaking principles will fix the return to investors over that time-period. The results of the ROE estimation models discussed previously do not address the incremental risk associated with the fixed duration of the return that is being established in this proceeding. I would also note that Iowa's advance ratemaking principles statute (Iowa Code Section 476.53) is intended to "attract the development of electric power generating and transmission facilities within the state" and addressing this incremental risk is important to that goal.

Q. What is duration risk?

A. The concept of duration risk is often referenced in the context of fixed income investments such as treasury bonds or corporate bonds and is defined as the risk associated with interest rate volatility whereby increases(decreases) in interest rates decrease(increase) the price of the bond. In general, longer-term bonds face greater duration risk than short-term bonds.

In fact, as noted by both BlackRock and PIMCO, a general rule of thumb is that a 1 percent change in the interest rate will change the price of the bond in the opposite direction by 1 percent for every year of duration.[48] Therefore, as shown in Figure 11, a one percent increase in the interest rate will result in a 30 percent decline in the price of the bond for a 30-year bond while a 1-year bond will only experience one percent decrease in price. Therefore, the longer the term of the bond, the greater the interest rate or duration risk.

Figure 11: The Effect on Bond Prices of a 1% Increase in Interest Rates

Duration	Percent Change in the Bond Price
1 year	-1%
5 years	-5%
10 years	-10%
30 years	-30%

Q. Is the concept of duration risk also relevant for an equity investment?

A. Yes, it is. It is particularly important for the utility sector, a defensive sector, which is generally classified a bond proxy. As noted in Section III, the share prices of utility stocks are strongly inversely related to interest rates. Therefore, an increase in interest rates will decrease the share prices of utilities which will result in an increase in the cost of equity. As Dr. Morin noted in New Regulatory Finance:

> Outstanding bonds are in fact exposed to interest rate risk, that is, the risk that interest rates will rise and bond prices will fall, inflicting a capital loss on bondholders. This risk can rise substantially in periods of volatile interest rates. It should be kept in mind, however, that utility stocks are highly interest-sensitive. These stocks provide a return to their holders predominately in the form of a dividend yield, which is interest-rate sensitive. There is a well-known bond theorem that states that the longer the maturity of a security, the greater its price volatility. It is also a fact that

[48] *See* PIMCO, Understanding Investing: Duration, https://www.pimco.com/en-us/resources/education/understanding-duration; and BlackRock, Understanding Duration, 2004, https://www.blackrock.com/fp/documents/understanding_duration.pdf.

> common stocks have an infinite maturity, and therefore bonds have a shorter maturity. Thus, if interest rates fall, the price of a publicly utility's stock would increase more than the price of its bonds. But the converse is also true. If interest rates were to rise, the common stock price would fall more. And this is precisely why interest-sensitive common stocks would be riskier than bonds.[49]

Q. Are interest rates expected to increase over the near-term?

A. Yes. As discussed in Section III, investors expect long-term interest rates to increase in response to increased inflation and the economic recovery from the COVID-19 pandemic. The expected increase in interest rates indicates that the cost of equity for the utility sector is likely to rise over the near-term. Therefore, there is significant duration risk associated with establishing a return in the current market environment for a fixed 30 to 40 year period. This highlights the importance of determining an incremental return that is sufficient to compensate investors for the increased duration risk.

Q. How did you estimate the incremental return that would be appropriate for the purposes of establishing the ROE for the fixed period of 30 to 40-years?

A. I determined a reasonable incremental return by comparing the average authorized ROEs over a historical time-period to the authorized ROEs established by the Board in the Company's previous advance ratemaking decisions. In this analysis, I calculated the average authorized ROEs for electric utility rate case determinations in the year in which the Board's decision in the Company's prior advance ratemaking determinations was issued and compared that average to the ROE that the Board authorized for the Company.

[49] New Regulatory Finance, Roger A. Morin Ph.D., Public Utility Reports, 2006, at 127.

Q. Why did you rely only on the ROE determinations in rate cases in the annual average of authorized ROEs?

A. As discussed previously, the current market data is being used to establish a base ROE. This data is consistent with the data that would typically be relied upon by commissions in the determination of an ROE in a rate case proceeding, setting the return on equity for a company's entire rate base. These determinations are made with the understanding that the company has the ability to refile a rate proceeding more frequently than a 30-to 40-year period. Therefore, it is reasonable to conclude that the average of authorized ROEs for rate cases across the country are not set taking into consideration the long-term risk associated with a change in the cost of equity.

Q. Please summarize the results of your analysis.

A. As shown in Figure 12 below and MidAmerican Bulkley Direct Exhibit-ROE, Schedule 8, my analysis indicates that the incremental return that has historically been authorized in setting the ROE for advance ratemaking principles is approximately 142 to 149 basis points.

Figure 11: MidAmerican Iowa Advance Ratemaking Docket Allowed ROEs Compared with Historical Authorized Returns for U.S. Electric Utilities

YEAR	MIDAMERICAN - ADVANCE RATEMAKING CASES			AVERAGE ALLOWED ROE ELECTRIC RATE CASE	INCENTIVE ROE PREMIUM
	DOCKET NO.	DATE OF ORDER	ALLOWED ROE		
2002	RPU-2001-0009	May-02	12.23%	11.21%	1.02%
2003	RPU-2002-0010	May-03	12.29%	10.96%	1.33%
2003	RPU-2003-0001	Oct-03	12.20%	10.96%	1.24%
2005	RPU-2004-0003	Jan-05	12.20%	10.51%	1.69%

2006	RPU-2005-0004	Apr-06	11.90%	10.34%	1.56%
2007	RPU-2007-0002	Jul-07	11.70%	10.32%	1.38%
2008	RPU-2008-0002	Jun-08	11.70%	10.37%	1.33%
2008	RPU-2008-0004	Aug-08	11.70%	10.37%	1.33%
2009	RPU-2009-0003	Dec-09	12.20%	10.52%	1.68%
2013	RPU-2013-0003	Aug-13	11.63%	9.82%	1.81%
2015	RPU-2014-0002	Jan-15	11.50%	9.60%	1.90%
2015	RPU-2015-0002	Aug-15	11.35%	9.60%	1.75%
2016	RPU-2016-0001	Aug-16	11.00%	9.60%	1.41%
2018	RPU-2018-0003	Dec-18	11.00%	9.56%	1.44%
Mean			11.76%	10.27%	1.49%
Median			11.70%	10.35%	1.42%

Q. How did you use this information to assess the reasonableness of MidAmerican's requested 11.25 percent ROE?

A. As discussed previously, based on the results of the traditional ROE estimation methodologies, I conclude that the cost of equity for MidAmerican is 10.30 percent. Adding the average differential between authorized ROEs over time to my recommendation results in an ROE of 11.72 percent to 11.79 percent, which is 47 to 54 basis points higher than the Company's request. Therefore, I conclude that the Company's requested ROE of 11.25 percent is reasonable.

Q. What is your conclusion regarding a reasonable rate to be used for AFUDC for Wind PRIME?

A. Based on my conclusion that a reasonable ROE for MidAmerican would be 10.30 percent, and the fact that AFUDC rates have historically been set at 10.00 percent in the Company's advance ratemaking principles cases, I conclude that 10.00 percent is a reasonable return on equity for use in the calculation of AFUDC.[50]

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

[50] Iowa Utilities Board, In RE: MidAmerican Energy Company, Docket No. RPU-2018-0003, Final Decision and Order, December 4, 2018, p. 20-21. See also, Docket No. RPU-2014-0002, Order Approving Settlement with Modifications, January 20, 2015, p. 19.

AFFIDAVIT OF ANN E. BULKLEY

COMMONWEALTH OF MASSACHUSETTS	:	
	:	**SS:**
COUNTY OF MIDDLESEX	:	

I, Ann E. Bulkley being first duly sworn on oath, depose and state that I am the same person identified in the foregoing Direct Testimony, that I have caused the Direct Testimony, including any original exhibits, to be prepared and am familiar with the contents thereof; and that the Direct Testimony, including any original exhibits, is true and correct to the best of my knowledge, information and belief as of the date of this Affidavit.

/s/ [redacted]
Ann E. Bulkley

Subscribed and sworn to before me,
a Notary Public in and for said County
ad State, this 14th day of Jan, 2022.

/s/ [redacted]
Notary Public
My commission expires on Nov. 27, 2026

REGINA A. KOLB
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires On
November 27, 2026

IOWA UTILITIES BOARD

IN RE: MIDAMERICAN ENERGY COMPANY	DOCKET NO. RPU-2022-0001

REHEARING FINAL ORDER AND CONCURRENCE

PROCEDURAL BACKGROUND

On January 19, 2022, MidAmerican Energy Company (MidAmerican) filed with the Utilities Board (Board) an application for a determination of ratemaking principles regarding the company's Wind PRIME project pursuant to Iowa Code § 476.53. MidAmerican's current request for advance ratemaking principles is for up to 2,042 megawatts (MW) of wind generation and 50 MW of solar generation. With MidAmerican's original application, it also filed a request for waiver, which requested a waiver of Board rules 199 Iowa Administrative Code (IAC) 20.9(1) and (2), as they apply to MidAmerican's energy adjustment clause (EAC) and 199 IAC 41.3(1)(c)-(g) to the extent information requested by such rules is not reasonably available and present in MidAmerican's application.

The parties to this docket are: the Office of Consumer Advocate (OCA), a division of the Iowa Department of Justice; the Environmental Law and Policy Center, Iowa Environmental Council, and Sierra Club (collectively, Environmental Intervenors); the Iowa Business Energy Coalition (IBEC); Iowa Business for Clean Energy (IA BCE); Iowa Association of Municipal Utilities (IAMU); Interstate Power and Light Company (IPL); and Microsoft Corporation and Google LLC (collectively, Tech Customers), as Meta Platforms, Inc. (formerly Facebook, Inc.) withdrew as a party.

On April 27, 2023, the Board issued a final order (Final Order) in which it granted ratemaking principles for Wind PRIME. On May 17, 2023, both the Tech Customers and MidAmerican filed separate applications for reconsideration. On June 15, 2023, the Board issued an order granting motions for reconsideration with a dissenting opinion.

On July 14, 2023, the Board issued an order that established the hearing start date as October 10, 2023. On August 9, 2023, MidAmerican filed rehearing direct (supplemental) testimony for witnesses Thomas Specketer and Adam Jablonski. Also on August 9, 2023, MidAmerican, OCA, and the Environmental Intervenors (Settling Parties) filed a joint motion to approve revised stipulation and agreement, which included a revised stipulation and agreement that has 13 proposed ratemaking principles (Settlement Agreement). While there are five parties inclusive in the Settling Parties, only the Tech Customers are objecting to the Settlement Agreement as proposed.

On August 14, 2023, IAMU filed comments on the revised settlement that state it "does not include any terms or principles that are detrimental to the interests of IAMU's members or to the Joint Owners of MidAmerican's electric generating units…." IAMU urged the Board to accept the revised settlement. On August 23, 2023, the Tech Customers filed comments on the revised settlement and a request to allow testimony.

On August 29, 2023, MidAmerican filed revised rehearing direct testimony for Mr. Specketer.

OCA and MidAmerican, respectively, filed responses to comments on the revised settlement.

On September 8, 2023, the Tech Customers filed Rehearing Rebuttal Testimony of witness Jeffry Pollock.

On September 21, 2023, MidAmerican filed Rehearing Rebuttal Testimony of Mr. Specketer, Mr. Jablonski, and Michael Fehr. OCA filed a statement in lieu of testimony.

The hearing was held as scheduled on October 10, 2023.

CONDITIONS PRECEDENT

Iowa Code § 476.53(3)(a) states that the Board shall specify in advance and in a contested case proceeding the ratemaking principles that will apply when the costs of the electric generating facility are included in rates. Iowa Code § 476.53(3)(b) states the Board is not limited to traditional ratemaking principles or traditional cost recovery mechanisms in determining applicable advance ratemaking principles. Iowa Code § 476.53(3)(c) requires the Board to make two findings prior to considering the proposed advance ratemaking principles.

First, the utility must have in effect a Board-approved energy efficiency plan. Second, the utility must demonstrate that it has considered other sources for long-term electric supply and that the proposed facility is reasonable when compared to other feasible alternative sources of supply. The Board stated in Docket No. RPU-01-9, advance ratemaking decisions have a greater long-term impact than other decisions made by the Board because the advance ratemaking principles approved by the Board cannot be revisited in a general rate case proceeding and will be applicable for the life of the assets. (MidAmerican Energy Company, "Order," Docket No. RPU-01-9, pp. 3-4 (May 29, 2002).) While one of the goals of Iowa Code § 476.53 is to encourage the development of renewable generating facilities, the requested advance ratemaking principles must be balanced with the impact on ratepayers and not be built at any cost. (*Id.*)

As part of determining applicable advance ratemaking principles, the Board must address MidAmerican's compliance with the statutory requirements in Iowa Code § 476.53(3)(c). In its Final Order, the Board found that MidAmerican met the conditions precedent for Wind PRIME based upon a no net cost analysis.

A. Iowa Code § 476.53(3)(c)(1)

Iowa Code § 476.53(3)(c)(1) requires MidAmerican to have in effect a Board-approved energy efficiency plan required pursuant to Iowa Code § 476.6(15). MidAmerican's Board-approved energy efficiency plan was not a contested issue. MidAmerican provided that its plan was approved February 18, 2019, for years 2019-2023. (*MidAmerican Energy Co., Application for a Determination of Ratemaking Principles,* Docket No. RPU-2022-0001, p. 5 (Jan. 19, 2022); *see also* Docket No. EEP-2018-0002.) MidAmerican's energy efficiency plan for 2024-2028, identified as Docket No. EEP-2022-0156, was filed on February 1, 2023, with a decision filed on October 24, 2023.

Compliance with this statutory requirement was not contested, and this condition has been met.

B. Iowa Code § 476.53(3)(c)(2)

The second finding the Board is required to make is whether MidAmerican has demonstrated that it has considered other sources for long-term electric supply and that the proposed generating facilities are reasonable when compared to other feasible alternative sources of supply. In Docket No. RPU-05-4, the Board stated:

> While MidAmerican has not demonstrated an immediate need for the wind facility (or any other generation facility) in the sense that it will be unable to meet customers' demand in 2007-2009 without the facility, the Board does not believe

> a determination of need requires a showing that the lights will go out if the facility is not built.

(*MidAmerican Energy Co., Order Approving Stipulation and Agreement,* Docket No. RPU-05-4, p. 6 (April 18, 2006).) The Board further stated:

> In generation planning, the general rule has traditionally been that the longer a utility can avoid building generation, the better off customers are, because new generation costs are deferred. However, general rules often have exceptions. A question posed to MidAmerican was whether the project would be more cost-effective if delayed for two to three years. The economic analysis filed showed it would not be and that, in fact, it might not be feasible for MidAmerican to pursue the project in two or three years, depending on the level of the federal production tax credit at that time.

(*Id.* at 7.)

The Board will discuss each element individually.

1. *Alternative Sources of Supply*

Any comparison of feasible alternative sources of supply must consider the type of generating asset for which advance ratemaking principles are requested and the cost profile and manner in which the utility receives the desired energy and capacity. This requires a quantitative analysis to demonstrate the utility's need if the proposed facilities do not show economic benefits to utility ratepayers. As shown in *NextEra*, customers do have a need for low-cost energy and reasonable prices, and, therefore, need can be shown by significant customer benefits. (*See generally NextEra Energy Resources LLC v. Iowa Util. Bd.,* 815 N.W.2d 30 (Iowa 2012).) The Board previously found that MidAmerican's consideration of alternative sources of supply failed "to demonstrate its reasonableness compared to feasible alternatives under a traditional utility view." (*Final Decision and Order,* p. 48 (April 27, 2023).)

MidAmerican asserts it did consider other sources for long-term electric supply and that the proposed facilities are reasonable in comparison. (*See generally, Application*, pp. 6-7 (Jan. 19, 2022).) MidAmerican witness Neil Hammer testified that nine planning criteria were used to complete this evaluation: (1) cost; (2) cost robustness; (3) environmental reasonableness; (4) system reliability; (5) economic development; (6) geo-political uncertainty; (7) flexibility/optionality; (8) diversity; and (9) resource availability/stability. (MidAmerican Hammer Direct, pp. 2, 28.) Mr. Hammer testified that wind and solar performed the highest in six out of the nine categories. (MidAmerican Hammer Rebuttal, p. 3.) Mr. Hammer further testified that the proposed generation facilities would help meet customers' needs, including reasonable cost, environmental reasonableness, economic development, addressing geo-political uncertainty, diversity, and resource availability/stability. (MidAmerican Hammer Direct, pp. 7, 29-45.) Mr. Hammer also provided testimony regarding coal, oil, natural gas, nuclear, storage, biomass, and hydroelectric generation sources. (*Id.* at 27-28.) When evaluating renewable generation sources, Mr. Hammer testified that availability, economics, and maturity were considered. (*Id.* at 50-51.) Mr. Hammer reiterated in his later testimony that Wind PRIME was compared to "natural gas-fired generation, coal-fired generation, nuclear-fueled generation, storage of various types (battery, hydrogen, and pumped storage), and renewable generation, including wind and solar, biomass, hydroelectric, and geothermal generation." (MidAmerican Hammer Additional Testimony, p. 2.)

Mr. Hammer then testified that a resource plan is not required because Wind PRIME is not replacing existing generation. Wind PRIME provides accredited capacity benefits as well as significant emissions-free energy benefits. (MidAmerican Hammer

Rebuttal, p. 2.) Mr. Hammer testified that both wind and solar are reasonable long-term supply options. (*Id.* at 3.) As far as generation diversity, Mr. Hammer testified that "the criticism that MidAmerican has not demonstrated sufficient diversity is based on a narrow MidAmerican-focused view that overlooks the benefits of operating in the [Midcontinent Independent System Operator] MISO market footprint. While there is a significant amount of wind energy in Iowa, broader regional market considerations are a critical frame of reference." (*Id.* at 9.) Mr. Hammer provided testimony that for winter specifically, wind adds more energy than solar, which helps customers during the home heating season. (*Id.* at 10.)

Mr. Hammer testified that while intervenors discussed the need for resource planning, resource planning is not required under Iowa law. (MidAmerican Hammer Surrebuttal, p. 2.) Mr. Hammer testified that MidAmerican "investigated [power purchase agreements] PPAs in light of the [Inflation Reduction Act of 2022] IRA, and found that Wind PRIME's cost of energy is quantitatively lower than current and predicted PPA prices following enactment of the IRA." (*Id.* at 8.) Mr. Hammer interprets the advance ratemaking reasonableness standard to encompass "both cost and qualitative, non-cost factors," which he testified the nine-factor analysis assesses. (*Id.*) In reviewing Wind PRIME, MidAmerican did not look to exclude existing, dispatchable generation, but to add incremental, long-term generation. (*Id.* at 9.)

Mr. Hammer testified that the Zero Emissions Study (ZES) performed by MidAmerican was "performed in 2019 and is significantly outdated, but beyond that it was never intended to be part of the reasonableness analysis for Wind PRIME or any other resource recommendation made under the advance ratemaking statute." (*Id.* at 20.) Mr. Hammer also testified that "[i]t's important to recognize that the study was an early study of the resource transition, well ahead of the discussions by MISO regarding seasonal resource adequacy." (*Id.*) Additionally, Mr. Hammer testified that the Siemens study is also outdated as it is from 2019-2020, and was not intended to be used for Wind PRIME or any advance ratemaking proceeding. (*Id.* at 21.) Similarly to the ZES, the Siemens study was conducted early on in the resource transition and prior to MISO changing to a seasonal resource adequacy construct. (*Id.* at 22.)

In direct testimony, Tech Customers witness Jeffry Pollock testified "the Board should consider whether MidAmerican has adequately evaluated whether PPAs are a feasible alternative." (Tech Customers Pollock Direct, p. 16.) Mr. Pollock testified that MidAmerican did not consider PPAs as a feasible alternative when evaluating Wind PRIME. (*Id.* at 15.) For capacity shortfalls, Mr. Pollock testified that other feasible alternatives could be zonal resource credits or short-term bilateral PPAs. (*Id.* at 16.) Mr. Pollock testified that Wind PRIME is not needed for capacity or energy. (*Id.* at 19.) Mr. Pollock testified that:

> MidAmerican did not consider procurement strategies other than self-build rate base projects. Other than providing a generic discussion of possible alternatives, MidAmerican failed to provide even a high-level (back-of-the-envelope) analysis demonstrating how Wind PRIME would be more for its customers than other feasible options or conduct a request for proposal (RFP) for market pricing information.

(*Id.* at 20.) Mr. Pollock testified that MidAmerican should have considered options such as different technologies, sizes, and lifespans, which Mr. Pollock asserts MidAmerican did not do. Mr. Pollock testified that MidAmerican "summarily rejected other feasible alternatives." (*Id.* at 21-22.) Mr. Pollock also testified that MidAmerican should have provided evidence that Wind PRIME would "create a more diverse energy supply, improve system reliability, and result in a lowering of costs relative to other feasible alternatives." (*Id.* at 24.)

In response, Mr. Specketer testified to what he described as "unfavorable characteristics" of PPAs: (1) imputed debt on capital structure, (2) no residual value of the asset, (3) shifting of risk to MidAmerican, (4) loss of economies of scale, (5) higher costs of debt, and (6) operational risk of the underlying asset. (MidAmerican Specketer Surrebuttal, pp. 2-3.) Mr. Specketer also testified that MidAmerican did not issue a request for proposal for a PPA; however, MidAmerican is aware of PPA pricing trends within the marketplace. (*Id.* at 3-4.)

Mr. Pollock testified that MidAmerican did not provide any type of resource plan as evidence that Wind PRIME is needed. (Tech Customers Pollock Additional Direct and Rebuttal, p. 4.) Mr. Pollock further testified that MidAmerican still had not considered a PPA or RFP when evaluating Wind PRIME. (*Id.* at 7.)

Mr. Pollock testified that if MidAmerican entered into a PPA arrangement, there likely would be safeguards to protect customers, such as credit support so the sponsor can obtain financing, performance metrics, and due diligence review for quality developers. (Tech Customers Pollock Surrebuttal, pp. 7-8.)

Mr. Pollock again testified that during Wind VII, MidAmerican used a resource plan that compared that project to other types of generation and to a PPA, which Mr. Pollock testified MidAmerican did not do so while planning Wind PRIME. (Tech Customers Pollock Additional Testimony, pp. 3-4.) Mr. Pollock testified that during Wind VII, MidAmerican completed a six-stage process, of which the sixth stage was an eight-factor qualitative analysis. (*Id.* at 2.) Mr. Pollock's testimony asserts that for Wind PRIME MidAmerican skipped the first five stages and only utilized the sixth stage. (*Id.*

at 2-3.) Mr. Pollock testified that “because MidAmerican refuses to ever consider procuring renewable and carbon free energy from the competitive marketplace, the Board has no way to assess whether these alternatives would be preferable and provide greater benefits to customers than a self-build project, which provides a guaranteed return to MidAmerican’s shareholder.” (Tech Customers Pollock Rehearing Rebuttal, pp. 11-12.)

2. *Project Economics*

The issue being addressed by the Board in this proceeding is whether MidAmerican satisfied the statutory requirement to consider other alternative sources of electric supply, which requires the Board to analyze the project economics. To determine whether Iowa Code § 476.53(3)(c)(2) was met, the Board must compare the utility’s benefits of ownership to costs of other generation resources. During this proceeding, MidAmerican asserted this project could be provided to ratepayers at no net cost; however, during the rehearing, MidAmerican asserted that based upon revised economics, Wind PRIME is now a net benefit to Iowa ratepayers. (MidAmerican Specketer Rehearing Direct (Supp), p. 5.) The Board did find previously that Wind PRIME was reasonable when compared to feasible alternatives based upon a no net cost rationale. (*Final Decision and Order,* p. 48 (April 27, 2023).)

Mr. Hammer testified, “Wind generation that provides additional energy with no emissions and that produces economic benefits for the State of Iowa, and that is projected to be delivered at no net cost to customers, should not be considered unreasonable through a narrow focus on accredited capacity.” (MidAmerican Hammer Rebuttal, p. 4.)

In rehearing supplemental direct testimony, Mr. Specketer testified Wind PRIME will be a net benefit to Iowa ratepayers. (MidAmerican Specketer Rehearing Direct (Supp), p. 5.) He testified that financial benefits from Wind Prime will exceed the costs of the project. (*Id.*) Mr. Specketer testified "[t]here will be years where the benefits exceed the costs, and . . . years where the costs exceed the benefits," but overall the benefits will exceed the costs. (*Id.*)

Based on Mr. Specketer's testimony, Mr. Pollock responded that Wind PRIME 2.0 is a more costly version of Wind PRIME that the Board did not approve in its Final Order. (Pollock Rehearing Rebuttal Testimony, p. 1.) Specifically, Mr. Pollock testified that Wind PRIME 2.0 will cost on a net present value more for customers. (*Id.* at 2.) In response, Mr. Specketer again testified that there will be a net benefit for customers as the benefits will exceed costs. (MidAmerican Specketer Rehearing Rebuttal Testimony, p. 2.) Mr. Specketer admits there will be a lower benefit for customers pursuant to the revised modeling of the project; however, a lower benefit does not necessarily mean there are increased costs for customers as there will still be a benefit to customers from the project. (*Id.* at 2-3.)

3. Board Discussion

In its Final Order, the Board found that "the ZES is a persuasive piece of evidence in the record as to what generation assets would improve reliability." (Final Order, p. 34.) The Board also found solar generation to be better situated to meet reliability needs within MidAmerican's exclusive service territory. (*Id.*)

The statute does not require that Wind PRIME be the most reasonable alternative, but a reasonable alternative, to other sources of supply. It is undisputed that over the past 20 years, the advance ratemaking statute has been used by electric utilities to add additional electric generation facilities to individual portfolios. Iowa Code § 476.53(1) provides the legislative intent of the advance ratemaking statute; therefore, it is not for the Board to determine whether that intent has been met or should be revised. However, it is the Board's responsibility to ensure that Iowans are receiving reliable service at just and reasonable rates. To further that responsibility, the Board will require electric utilities requesting future advance ratemaking principles to provide sufficient information that shows the electric utility has considered other sources for long-term electric supply and that the proposed generating facilities are reasonable when compared to other feasible alternative sources of supply, as required by Iowa Code § 476.53(3)(c)(2). This can be accomplished by the utility including detailed information regarding its resource planning process with a 10-year outlook. This information would identify potential generating alternatives available and what impact each alternative would have on the utility's customers. (*See MidAmerican Energy Co., Order Approving Stipulation and Agreement,* Docket No. RPU-07-2 (July 27, 2007).)

While the comparison of reasonable alternatives may not have been as robust as in other proceedings, MidAmerican showed the analysis it used when comparing Wind PRIME against other sources of supply. PPAs and RFPs are generally part of the analysis, and while the Board considers that comparison a valuable part of the analysis, MidAmerican provided information as to why more detailed PPA information was not provided. Additionally, MidAmerican included project economics where MidAmerican additionally asserted Wind PRIME would be at no net cost to customers, which then after revised project economics became a net benefit. Based on the information provided, the alternative sources of supply and project economics evaluation is sufficient to show that Wind PRIME is reasonable when compared to other feasible alternative sources of supply. For these reasons, the Board finds that MidAmerican has complied with the requirements of Iowa Code § 476.53(3)(c)(1)-(2) and that ratemaking principles should be granted.

ADVANCE RATEMAKING PRINCIPLES

In the August 9, 2023 Settlement Agreement, the Settling Parties proposed 13 advance ratemaking principles. Board rule 199 IAC 7.18 provides that the Board will not approve a settlement unless it "is reasonable in light of the whole record, consistent with law, and in the public interest." While the Board focuses on the reasonableness of the entire settlement, the Board also examines issues individually in making its overall determination.

In conducting its review, the Board considered the record as a whole, including all comments and objections filed. In addition, Board subrule 199 IAC 7.18(4) states:

> A party contesting a proposed settlement must specify in its comments the portions of the settlement that it opposes, the legal basis of its opposition, and the factual issues that it contests. Any failure by a party to file comments may, at the board's or presiding officer's discretion, constitute waiver by that party of all objections to the settlement.

The parties within this proceeding provided voluminous amounts of testimony and comments. To help ensure a more robust and complete record in this instance, the Board will utilize its discretion and not consider issues waived in regard to the Settlement Agreement and the proposed advance ratemaking principle.

The Board will therefore address each advance ratemaking principle contained in the proposed Settlement Agreement, including whether any parties object to or contest certain proposed advance ratemaking principles.

A. Iowa Jurisdictional Allocation

The Iowa Jurisdictional Allocation proposed advance ratemaking principle states, "Wind PRIME will be allocated to Iowa in the same manner as the Greater Des Moines Energy Center, Walter Scott Jr. Energy Center Unit No. 4, and prior wind power projects (i.e., Wind I – Wind XII)."

In the Final Order, the Board found that allocating all of the risk of Wind PRIME to Iowa ratepayers is not in the public interest. (Final Order, p. 70.) The Board then declined to assign all costs of Wind PRIME to Iowa ratepayers without a showing of compensation for the benefits received by Illinois ratepayers. (*Id.* at 70-71.)

Mr. Specketer testified that this proposed advance ratemaking principle is the same as proposed and approved in Wind XI and Wind XII, which means "MidAmerican will allocate to the Iowa jurisdiction all of the Wind PRIME capital costs and expenses that would be allocated to Illinois under traditional allocation principles." (MidAmerican Specketer Direct, pp. 3-4.) Mr. Specketer testified that this advance ratemaking principle is being proposed due to Iowa's energy policy — Iowa Code § 476.53 — and allows Iowa customers to receive the benefits of such a policy. (*Id.* at 4.) Mr. Specketer also testified to the different regulatory scheme in Illinois, which has retail electric competition and that the Illinois Power Agency procures electric supply for incumbent providers. (*Id.*) Lastly, Mr. Specketer testified to the 1% portion allocated to South Dakota. (*Id.*)

At the October 10 Hearing, Mr. Specketer testified that Illinois customers will not receive any capacity benefits from Wind PRIME. (RT[1], p. 90.) He testified that, "All the capacity benefits from Wind PRIME will be allocated to either Iowa or there's a very

[1] RT means Rehearing Transcript filed in the Board's electronic filing system on October 24, 2023.

small portion that gets allocated to South Dakota under the Iowa Jurisdictional Allocation." (*Id.*) MidAmerican separated the "capacity planning for Iowa and South Dakota from Illinois." (*Id.*)

The Tech Customers support the Final Order and the premise that Iowa customers only pay for assets assigned to Iowa. (Tech Customers Motion for Reconsideration and Clarification, pp. 9-10.) The Tech Customers further identified that the proposed advance ratemaking principle should more clearly establish how the Board will ensure that Iowa ratepayers are not subsidizing residents of other states. (*Id.*)

While the Board finds this ratemaking principle reasonable, future advance ratemaking proceedings will require further details about how Iowa ratepayers will be compensated for any allocation that may be made to other jurisdictions, specifically explaining how Iowa ratepayers are not subsidizing those other jurisdictions. Iowa ratepayers should not be required to pay for benefits received by other jurisdictions. In this instance, the evidence in the record states that Iowa customers receive all of the benefits from Wind PRIME; thus, the Board will not reject this advance ratemaking principle.

B. Cost Cap

In the proposed Cost Cap advance ratemaking principle, the wind-powered facilities have a cost cap of $2.106 million/MW (including allowance for funds used during construction, or AFUDC) and solar-powered facilities have a cost cap of $1.951 million/MW (including AFUDC). As proposed, the cost caps are soft caps, which means the Board must determine the prudence and reasonableness of any amount over the cost caps before MidAmerican can recover those costs from customers.

Mr. Fehr testified that “MidAmerican’s customers are not at risk for, and are protected against, inflationary pressures” by the Cost Cap ratemaking principle. (MidAmerican Fehr Surrebuttal, p. 10.)

Mr. Pollock testified that instead of a soft cap, the cost cap should be a hard cap. (Tech Customers Pollock Direct, pp. 38, 49; Tech Customers Additional Direct and Rebuttal Testimony, p. 17.) Mr. Pollock previously testified that if MidAmerican was confident in its cost cap analysis, “it should be willing to forgo recovery for costs that ultimately exceed the Cost Cap due to inflation.” (Tech Customers Additional Direct and Rebuttal, p. 14.) Mr. Pollock testified that “as a practical matter, it is *far* more difficult to demonstrate imprudence after-the-fact because MidAmerican controls all of the information necessary to conduct a complete evaluation of whether costs incurred above a cap are both prudent and reasonable.” (*Id.* at 16-17.) Mr. Pollock further testified that prior to the rate case, and thus a prudency determination, the costs that exceed the cost cap could still be included in revenue sharing. (Tech Customers Pollock Rehearing Rebuttal, p. 9.) Mr. Pollock also testified that by having a soft cost cap, MidAmerican would be less likely to provide Wind PRIME benefits at no net cost. (*Id.* at 10.) Mr. Pollock testified further that, “Although the new cost caps may be more realistic, the presence of a soft cap makes the project even less likely to be provided at no net cost to customers.” (*Id.*) Mr. Pollock testified that the Board should change the cost cap to a hard cap. (*Id.* at 16.)

At the October 10 Hearing, Mr. Specketer testified that MidAmerican has not committed to excluding overages in revenue sharing until a prudency review by the Board. (RT, p. 68.) Mr. Specketer testified that while the proposed 10.75% ROE would not apply, “all other ROE” would apply to any cost cap overages. (*Id.*)

The Board will approve the Cost Cap advance ratemaking principle with the limitation that if the cost cap is exceeded, any cost cap overages will be excluded from the revenue sharing calculation used to determine what amount, if any, is to be shared with customers. To further clarify, cost cap overages will be excluded from the denominator, but no income will be excluded from the numerator, in the revenue sharing calculations. If excess costs are determined to not be prudent in a future rate case, those costs will not be eligible to be included in revenue sharing; thus, excluding cost-overages from the revenue sharing calculation will protect customers until the Board determines the prudency of those costs. If during a rate case any excess costs are determined to be prudent, those costs can then be included in revenue sharing.

C. Size Cap

The proposed Size Cap advance ratemaking principle states, "The ratemaking principles shall be applicable to all new MidAmerican wind generation up to 2,042 MW and all new MidAmerican solar generation up to 50 MW-AC, built as part of Wind PRIME."

Mr. Pollock testified that it will take longer to deploy Wind PRIME than previous wind projects. (Tech Customers Pollock Rehearing Rebuttal, p. 12.) Mr. Pollock testified that if a smaller project was approved, deployment would not take as long and would lead to possible risks regarding inflation and supply chain issues. (*Id.*) Mr. Pollock testified that the Board should consider reducing the size cap. (*Id.* at 16.)

MidAmerican witness Fehr testified that the proposed size of the Wind PRIME project was derived by identifying wind projects from the MISO Generation

Interconnection Queue and that MidAmerican limited its evaluation to self-developed solar projects. (HT[2], pp. 109, 134, 168.)

At the rehearing, Mr. Fehr testified that the size cap remains appropriate because it advances the needs identified in the *NextEra* case and the advance ratemaking statute. (RT, p. 49.) Mr. Fehr also testified that the size cap is a maximum limit and that MidAmerican would not have to build up to that limit if "it just became obvious that it was going to be problematic." (*Id.* at 50.)

The Board notes that when MidAmerican originally proposed Wind PRIME, the proposed size cap was the same as the current proposal. While a more in-depth analysis beyond just looking at the MISO queue may be preferential when a utility is seeking to build more than 2,000 MW of generation, the statute requires that the proposed facility is reasonable, not the best alternative. MidAmerican used the same size cap throughout its evaluation, which is an integral part of the no net cost/net benefit analysis. The Board, therefore, finds that the Size Cap proposed advance ratemaking principle is reasonable.

D. Resource Evaluation Study

The proposed Resource Evaluation Study (RES) advance ratemaking principle states:

> MidAmerican commits to complete a Resource Evaluation Study ("RES") within 24 months of MidAmerican's acceptance of a Board Order establishing ratemaking principles in this proceeding. The RES results will be filed as an informational filing in a non-contested docket with the Board; MidAmerican agrees the Company will not file its next advance ratemaking principles application, a tariff for customer program(s) that include new generation facilities with an interconnection greater than fifty (50) megawatts or general Iowa electric rate case until the RES results are on

[2] HT means Hearing Transcript filed in the Board's electronic filing system on March 15 and 16, 2023.

> file with the Board, unless the Settlement Parties agree in writing to allow MidAmerican to file such a proceeding before the RES is completed and filed. The RES results must be on file with the Board for at least ninety (90) days prior to an advance ratemaking principles application or a general Iowa electric rate case, unless the Settlement Parties otherwise agree in writing. MidAmerican further agrees to complete an update to the RES within three (3) years of the filing of the RES. The full terms and conditions of the RES, which include dispute resolution provisions agreed to by the Settlement Parties, are described in Exhibit A of the RPU-2022-0001 Revised Stipulation and Agreement.

Mr. Pollock testified that the Tech Customers support the proposed RES advance ratemaking principle, but also testified to concerns about the stay-out provision and that the RES process would be repeated once instead of being an ongoing process. (Tech Customers Pollock Rehearing Rebuttal, pp12-13.)

During rehearing, Mr. Jablonski stated that a sizable amount of the Wind PRIME projects will go into service after the initial RES is complete. (RT, pp. 25-26.) However, MidAmerican commits to completing “an update to the RES within three (3) years of the filing of the RES.” (Revised Stipulation and Agreement, p. 3.) In completing such an update, MidAmerican would need to account for the additional facilities that go into effect after the primary RES is complete; therefore, absolving Mr. Pollock’s primary objection to the principle. (*See id.*)

The Board agrees that transparency with resource evaluation is paramount, especially for Iowa and the electric grid as a whole. While the Board may not have drafted the RES advance ratemaking principle to include a stay-out provision that allows settling parties to waive such a provision and a limited duration on the process itself, the Board determines that this proposed advance ratemaking principle is reasonable.

E. Depreciation

The proposed Depreciation advance ratemaking principle sets the depreciation life for the Wind PRIME wind facilities at 40 years and the solar facilities at 30 years. The proposed principle allows MidAmerican to revise the depreciable life if there is an independent depreciation expert that provides support for the revised useful life and it is then approved by the Board in a contested case proceeding. MidAmerican also agrees to perform a depreciation study as part of its next general Iowa electric rate case and that the prudency of any Wind PRIME repowering costs will be addressed in a subsequent rate proceeding, if applicable.

Mr. Specketer testified that if MidAmerican repowers any of the approved Wind PRIME generating facilities prior to the end of the depreciable life, MidAmerican would not remove the undepreciated portion from rate base for revenue sharing purposes. (RT, p. 99.)

Mr. Pollock testified that "the Board should also revise the depreciation ratemaking principle to require that MidAmerican not earn a return on any investment that is no longer used and useful due to repowering." (Tech Customers Pollock Rehearing Rebuttal, p. 17.)

The Board agrees that more review is needed when it comes to what is included in the revenue sharing calculation, including repowering; however, the Board has determined that this advance ratemaking proceeding is not the proper avenue for such review. This ratemaking principle is similar to previously approved ratemaking principles and no information has been provided to change the depreciable life of wind or solar facilities. Based upon that determination, the Board finds this advance ratemaking principle reasonable, which is consistent with the Board's previous determination. (*See* Final Order, p. 92 (discussing the approved depreciation advance ratemaking principle).)

F. Return on Equity

The proposed Return on Equity (ROE) advance ratemaking principle allows MidAmerican the opportunity to earn a 10.75% return on the common equity portion of Wind PRIME. A 10.0% return on common equity rate will be used as an AFUDC rate to be applied for construction work in progress. The AFUDC rate, when used, will be calculated consistent with the Uniform System of Accounts.

Mr. Specketer testified at the rehearing that he believes this ratemaking principle is reasonable. (RT, p. 85) The Settlement Agreement includes a 10.75% ROE, which locks in the return for 40 years. (*Id.* at 67.) To compensate for a long-term investment, Mr. Specketer testified that 150 basis points would be added to the average ROE, which would result in a proposal ROE of around 11.2%, without a settlement. (*Id.* at 65-66.) Mr. Specketer then testified that the ROE ratemaking principle provides "predictability and certainty." (*Id.* at 85.) Mr. Specketer further defined the 10.75% ROE as a hedge for customers against inflationary pressures because the ROE is set for the life of the asset. (*Id.*)

Mr. Pollock testified that the Tech Customers supported OCA's proposal of a 10% ROE. (Tech Customers Pollock Additional Direct and Rebuttal, p. 23.) Mr. Pollock testified that a 10.75% ROE is not appropriate as it is still an above-market return. (Tech Customers Pollock Rehearing Rebuttal, p. 13.) Mr. Pollock testified that due to MidAmerican's experience with wind projects and because wind is not a new technology, a premium ROE is not justified. (*Id.*)

The Board previously determined that it was "not in the public interest to award an ROE that overcompensates the utility, especially given the practice in advance ratemaking of allowing an ROE to be for the life of the assets." (Final Order, p. 74 (modifying a proposed advance ratemaking principle that would have allowed MidAmerican to have an 11.00% ROE).) The Board also found the previous ROE was not reasonable in light of the record as a whole. (*Id.*) The record in this docket shows that there is an argument that the 10.75% included in the Settlement Agreement can be considered a premium ROE. The current ROE settlement ratemaking principle includes a lower ROE than the previous settlement and what was originally requested in MidAmerican's application. When reviewed with the other provisions of the Settlement Agreement, and based on the record as a whole, the Board finds that the proposed ROE advance ratemaking principle is reasonable.

G. Cancellation Cost Recovery

The proposed Cancellation Cost Recovery advance ratemaking principle allows for MidAmerican to amortize over a ten-year period any prudently incurred and unreimbursed costs, as long as the Wind PRIME site is canceled for good cause. If the advance ratemaking principle is necessary, the annual amortization is recorded above-the-line and included in revenue requirement calculations.

No parties contested this proposed advance ratemaking principle. The Board has previously approved similar advance ratemaking principles in other dockets, and similarly finds this proposal is reasonable.

H. Environmental Benefits, CO2 Credits and the Like

The proposed advance ratemaking principle for environmental benefits, CO2 Credits, and the like partly contain the following provisions:

> All environmental benefits of Wind PRIME, wind- and solar-related, shall be allocated to each of the customer classes based on class kilowatt hour ("kWh") sales. Upon the written election by any Individual Customer Rate ("ICR") customer ("Electing Customer"), MidAmerican shall retire, or retire on behalf of the Electing Customer (so long as retirement on behalf of such customer does not jeopardize MidAmerican's ability to comply with environmental regulations or constitute a transfer of the environmental and compliance benefits), through the Midwest Renewable Energy Tracking System ("M-RETS"), or other comparable process acceptable to the Electing Customer, such Electing Customer's allocation of the environmental and compliance benefits of Wind PRIME that MidAmerican does not need for environmental compliance.
>
> …
>
> The Iowa portion of any revenues from the sale of environmental or compliance related benefits associated with Wind PRIME shall be recorded as a regulatory liability and will be excluded from the Iowa Energy Adjustment Clause ("EAC") as approved in MidAmerican's 2013 rate case until the investment and all other costs and benefits of Wind PRIME are included in base rates or the EAC in a future rate proceeding. For subsequent rate cases, the Iowa jurisdictional portion of the investment and all other costs and benefits of Wind PRIME shall be included in base rates or the EAC, and the Iowa jurisdictional portion of any revenues from the sale of environmental or compliance related benefits associated with Wind PRIME shall be included in the EAC.

The proposed advance ratemaking principle further identifies notice requirements on behalf of certain customers and MidAmerican.

As the Board previously found in its Final Order, "the record supports the reasonableness of tracking environmental benefits and ensuring that the monetary value of such benefits is assigned in support of the proposed project. The Board has clear authority to allow the environmental benefits to be tracked in a regulatory liability account, and it is in the public interest to ensure that the benefits are monetized and included as related revenue for the project." (Final Order, p. 75.) There are no objections to this proposed advance ratemaking principle. The Board finds this proposed advance ratemaking principle is reasonable.

I. Federal Production Tax Credits

The proposed Federal Production Tax Credit (PTC) advance ratemaking principle states that any PTCs associated with Wind PRIME will be recorded above-the-line in the Federal Energy Regulatory Commission (FERC) account 409.1, or any successor account for recording such credits, and the PTCs will be excluded from the Iowa EAC. After a subsequent Iowa general electric rate proceeding, any PTCs associated with Wind PRIME will then be included in the EAC.

No parties object to this proposed advance ratemaking principle. FERC account 409.1 is currently titled "Income taxes, utility operating income." The Board finds that this advance ratemaking principle is reasonable as any remaining PTCs associated with Wind PRIME will flow through the EAC at the time when Wind PRIME costs are included in base rates.

J. Iowa Energy Adjustment Clause and Rate Mitigation

The Settlement Agreement includes an Iowa EAC and Rate Mitigation proposed advance ratemaking principle.

> For EAC reconciliation filings in 2024 and after, MidAmerican will provide Energy Adjustment Clause ("EAC") stabilization relief to a targeted amount of $0.0125/kWh through the following steps, in this order:
> 1. $100 million of 2022 revenue sharing shall be allocated to a regulatory account, with amounts from that account to be credited to the EAC as needed to reach the targeted EAC