

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

Application of Enbridge Gas Utah to
Increase Distribution Rates and
Charges and Make Tariff
Modifications.

DOCKET NO. 25-057-06

Errata to the Direct Testimony and Exhibits of

Matthew P. Smith

On behalf of

~~United States Air Force~~ The Federal Executive Agencies

FEA Exhibit 2.0

September 16, 2025



BRUBAKER & ASSOCIATES, INC.

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DIRECT TESTIMONY OF MATTHEW P. SMITH**

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Direct Testimony of Matthew P. Smith

I. INTRODUCTION

1 **Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A Matthew P. Smith. My business address is 16690 Swingley Ridge Road,
3 Suite 140, Chesterfield, MO 63017.

4 **Q WHAT IS YOUR OCCUPATION?**

5 A I am a Consultant in the field of public utility regulation with the firm of Brubaker
6 & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

7 **Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND**
8 **EXPERIENCE.**

9 A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing in this proceeding on behalf of the Federal Executive Agencies ("FEA"). The FEA consists of certain agencies of the United States Government which have offices, facilities, and/or installations in the service area of Enbridge Gas - Utah ("EGU" or "Company"), such as Hill Air Force Base. The Department of Defense has been delegated authority by the General Services Administration to represent, through Department of the Air Force counsel, the consumer interest of the FEA in these proceedings under 40 U.S.C. §§ 501(c) and 121(d). Utility costs represent one of the largest variable expenses of operating federal offices, facilities, and installations, and all will be significantly affected by any action the Commission takes in these dockets. For these reasons, the FEA has a substantial interest in the above-captioned docket.

Q ARE YOU SPONSORING ANY ATTACHMENTS IN CONNECTION WITH YOUR TESTIMONY?

A Yes, FEA Exhibit 2.01 and FEA Exhibit 2.02.

II. SUMMARY

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A I will provide comments and recommendations on the Class Cost of Service ("CCOS"), specifically allocation methods used by EGU for distribution mains and other distribution equipment, the cost of which EGU has allocated to classes using its combined design day demand/throughput and distribution throughput

allocators. My silence in regard to any issue should not be construed as tacit agreement or an endorsement of EGU's position.

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS AND CONCLUSIONS.

A I recommend the Public Service Commission of Utah (the "Commission" or "PSCU"):

- Adopt my proposed CCOS study using Excess Design Day Demand and throughput to allocate the costs of large-diameter Intermediate High Pressure ("IHP") mains, as well as the costs of high-pressure feeder-line mains, compressor station equipment, and regulation station equipment to customer classes. Because my method better reflects class cost-causation, my CCOS study is appropriate to guide class revenue allocation.
- I recommend an allocation of the increase in this case based on my COSS, and a gradual movement to cost of service for all rate classes.

III. CLASS COST OF SERVICE

Q WOULD YOU PLEASE COMMENT ON THE BASIC PURPOSE OF A CCOS STUDY?

A After the utility's overall cost of service (or revenue requirement) is determined, a CCOS study is used to allocate the cost of service among the utility's customer classes. A CCOS study shows the extent to which each customer class contributes to the total cost of the system. For example, when a class produces the same rate of return as the total system, it returns to the utility just enough revenues to cover the costs incurred in serving that class (including a reasonable authorized return on investment). If a class produces a rate of return

below the system average, the revenues it provides for the utility are below the utility's cost of service. In this instance, the class receives a subsidy from other rate classes. If, on the other hand, a class produces a rate of return above the average, then that class pays more revenues than needed to pay the utility its cost of service, and actually also pays for part of the utility's costs to service other rate classes that produce below-average rates of return – in this case the class would pay a subsidy to cover the cost of serving other rate classes.

The CCOS study therefore is an important tool, because it shows the revenue requirement, or cost of service, for each class under current and proposed rates, which gauges whether the class is paying cost of service or if it is paying or recovering a subsidy from other rate classes.

Q SHOULD A CLASS'S RATES ALWAYS BE MOVED TO FULL COST OF SERVICE BASED ON THE RESULTS OF THE UTILITY'S CCOS STUDY?

A To the extent possible, yes, a utility's rates for its classes should be based on each class's respective cost of service. However, in instances where a full movement to cost of service for a utility's rates would cause rate shock for a particular customer class or classes, then the principle of gradualism can be applied to move each rate class gradually toward cost of service, therefore mitigating the impacts on customer classes and avoiding rate shock, while gradually moving each rate class to cost of service.

For example, the process of gradualism moves rate classes toward cost of service without excessive increases to any specific rate class. This includes

77 limiting rate class increases/decreases to a certain multiple of the system
78 average increase.

79 **IV. EGU'S CLASS COST OF SERVICE**

80 **Q HAVE YOU REVIEWED THE CCOS STUDY PREPARED BY EGU IN THIS**
81 **PROCEEDING?**

82 A Yes. I have reviewed the CCOS study prepared by Company witness Austin C.
83 Summers in his direct testimony, EGU Exhibit 5.0.

84 **Q HOW DOES THE COMPANY ALLOCATE THE COST OF DISTRIBUTION**
85 **MAINS TO CLASSES IN ITS CCOS?**

86 A EGU proposes to divide its distribution main investments into three categories:
87 small-diameter (6 inches or smaller) IHP mains, large-diameter (greater than 6
88 inches) IHP mains, and high-pressure feeder-line mains.¹ Distribution mains
89 are typically the largest component of rate base for a local distribution gas utility.

90 The costs of small-diameter IHP mains are allocated to classes by the
91 Company's Distribution Plant Factor study, used to determine the amount of
92 small mains necessary to provide service to smaller customers.

93 The costs of large-diameter IHP mains connecting the small-diameter
94 IHP mains to the high-pressure feeder-line mains are allocated to classes by

¹ Direct Testimony of Austin Summers at 2.

the Company's Distribution Throughput Study, which allocates costs to customer classes based on class throughput or commodity volumes.²

The costs of high-pressure feeder-line mains are allocated to classes by a weighted-average combination of Design Day Demand (60% weight) and annual usage or commodity throughput (40% weight).³ The combination of these factors results in a composite allocation factor that is generally known as the Peak and Average ("P&A") allocation factor.

Q IS THE COMPANY'S PROPOSAL FOR ALLOCATING THE COST OF SMALL-DIAMETER IHP MAINS TO CUSTOMER CLASSES REASONABLE?

A Yes. The Company's proposal results in allocating small-diameter IHP main costs to the customer classes that actually utilize small-diameter IHP mains. This allocator also appears to recognize the cost to connect customers to the Company's system of mains. Utilities design their system of mains to not only meet system peak day demands but also must design the mains to connect customers to the delivery system. As a result, I do not oppose this allocation.

² *Id.* at 2-6.

³ See 23 Dec 22 Order Dkt. No. 22-057-03 at 36 (finding that the 60%/40% weighting is consistent with previous DEU case).

110 **Q HOW DO UTILITIES TYPICALLY REFLECT THE COSTS OF CONNECTING**
111 **CUSTOMERS TO THE SYSTEM?**

112 A They classify the small mains cost as both customer related and demand
113 related. The customer allocation of small mains is typically measured using a
114 minimum-system study. The minimum-system study approximates the amount
115 of small-main investment that is incurred irrespective of the demands placed on
116 the small mains. In effect, small mains must have adequate length to connect
117 all customers to the system. The length of the small mains needed for this
118 purpose is independent from the demands placed on the small mains.

119 A review of EGU's Distribution Plant Factor Study for the small mains
120 shows it examines the main line directly connected to the service line within a
121 thousand feet of a service-tap point to ascertain the amount of main line
122 attributable to class meters.⁴ Based on my review, the Company's proposed
123 allocation of small-diameter IHP costs is essentially a small-mains adjustment
124 and results in very little small-main costs allocated to large high load factor
125 classes.

126 **Q DO LARGE TRANSPORTATION CUSTOMERS TYPICALLY UTILIZE**
127 **SMALL-DIAMETER DISTRIBUTION MAINS?**

128 A No, they do not. Large, high load factor transportation customers typically do
129 not utilize small-diameter mains because they are incapable of delivering the

⁴ Direct Testimony of Austin Summers at 3.

130 quantity of gas supply that these customers require. These customers are
131 connected directly to larger mains. Therefore, these customers should not be
132 allocated the costs of small-diameter mains.

133 A review of the Company's CCOS study shows that the Company's
134 Distribution Plant Factor study does indeed allocate very few small-diameter
135 IHP main costs to customer classes with larger gas demands. For example, the
136 TSL class is allocated 0.017% of the costs of small-diameter mains, which is a
137 logical result.⁵

138 **Q DO YOU AGREE WITH EGU'S PROPOSED CCOS STUDY ALLOCATION**
139 **METHOD FOR LARGE-DIAMETER AND FEEDER MAINS?**

140 A No, I do not. EGU's proposal in its CCOS study to allocate some categories of
141 distribution main costs on a P&A allocator does not reflect cost causation, and
142 therefore, is not reasonable. As explained above, large-diameter IHP main
143 costs are allocated on commodity throughput by the Company; high-pressure
144 feeder-line main costs are allocated on the P&A method. Allocating a portion of
145 main costs on a P&A allocator does not reflect the load characteristics of the
146 system that caused EGU to incur main capacity costs and therefore does not
147 follow sound cost causation principles.

⁵ EGU Ex. 5.03 at 6.

148 **Q IS THE P&A METHOD A LOGICAL METHOD OF COST ALLOCATION?**

149 A No. The P&A method typically uses the annual system load factor to determine
150 the percentage of fixed-delivery system investment allocated on annual system
151 throughput. As load factor (which is a measure of system efficiency) increases,
152 the percentage of transmission plant cost allocated on system throughput
153 increases. Large manufacturing customers use gas consistently throughout the
154 year and increase system load factor. Therefore, the P&A method is illogical
155 because it allocates even more costs to those customers that increase system
156 load factor and punishes efficient usage.

157 **Q IS THE P&A METHOD A TRUE COST ALLOCATION METHOD?**

158 A No. The P&A method is not a true cost allocation method as it introduces load
159 factor to temper costs between high load factor and low load factor customer
160 classes. As stated by the National Association of Regulatory Utility
161 Commissioners *Gas Distribution Rate Design Manual* ("NARUC Manual") in reference
162 to the P&A method:

163 This method reflects a compromise between the coincident and
164 noncoincident demand methods. Total demand costs are
165 multiplied by the system's load factor to arrive at the capacity
166 costs attributed to average use and are apportioned to the various
167 customer classes on an annual volumetric basis. The remaining
168 costs are considered to have been incurred to meet the individual
169 peak demands of the various classes of service and are allocated
170 on the basis of the coincident peak of each class. This method
171 allocates cost to all classes of customers and tempers the

172 apportionment of costs between the high and low load factor
173 customers.⁶

174 Essentially, the P&A method introduces customer class cost mitigation
175 into the cost allocation process. This is inappropriate. Instead, costs should
176 first be allocated on cost causation. After costs are properly allocated to
177 customer classes, any necessary cost mitigation to prevent rate shock for
178 particular customer classes should then be addressed through the class
179 revenue allocation process.

180 **Q PLEASE EXPLAIN HOW EGU DESIGNS ITS DISTRIBUTION SYSTEM.**

181 A Gas local distribution companies design and size their distribution systems
182 based on the peak demands of their customers, including the day of maximum
183 demand. The design of EGU's distribution system is no different.

184 **Q WHAT EVIDENCE HAS EGU PROVIDED TO CONFIRM IT DESIGNS ITS**
185 **DISTRIBUTION MAINS TO MEET SYSTEM PEAK DEMAND?**

186 A The Company has provided multiple discovery responses supporting the fact
187 that distribution main capacity is designed to meet system-peak demand. The
188 specific evidence is summarized below and included in EGU's discovery
189 responses attached as FEA Exhibit 2.01:

⁶ NARUC Gas Distribution Rate Design Manual, publish June 1989, pages 27 & 28.

- 190 1. EGU's natural gas facilities are designed to serve the aggregate peak
191 demand for all customer loads to ensure reliable and uninterrupted
192 natural gas service.⁷
- 193 2. Load factor is not one of the criteria considered by the Company in
194 terms of facilities required to serve a customer class.⁸
- 195 3. The Company identifies and recommends system improvements to
196 maintain reliability and meet customer needs during peak demand
197 conditions.⁹
- 198 4. The Company agrees that total usage is not a factor of how the
199 capacity of its distribution mains are designed, i.e., EGU's
200 demand-related costs.¹⁰
- 201 5. Demand-related costs are primarily incurred to meet the Design Day
202 Demand on the Company's system.¹¹

203 **Q THE COMPANY'S EVIDENCE INDICATES THAT THE PRIMARY PURPOSE**
204 **OF DISTRIBUTION MAINS IS TO MEET ALL CUSTOMER DEMANDS FOR**
205 **NATURAL GAS AT ALL TIMES. IF DISTRIBUTION MAINS WERE**
206 **DESIGNED TO MEET AVERAGE DEMAND, WOULD THIS PRIMARY**
207 **OBJECTIVE BE ACCOMPLISHED?**

208 **A** No. If distribution main capacity was designed to meet Average Demand, then
209 the Company would not be able to provide firm service on days when demand
210 exceeds the average. In this scenario, the Company would fail to achieve its
211 objective of meeting all customer demands for natural gas at all times.

⁷EGU's Response to FEA Data Requests 2.03, 2.04, 2.05, & 2.09. Included as FEA Exhibit 2.01 at 1-3 and 6.

⁸EGU's Response to FEA Data Request 2.06. Included as FEA Exhibit 2.01 at 4.

⁹EGU's Response to FEA Data Request 2.03. Included as FEA Exhibit 2.01 at 1.

¹⁰EGU's Response to FEA Data Request 2.08. Included as FEA Exhibit 2.01 at 5.

¹¹*Id.*

212 However, if mains are designed to serve Design Day Demand (which they are),
213 then it follows that the Company can meet all customer demands at all other
214 times when demand is less than the Design Day Demand. It is clear that Design
215 Day Demand is the driver of distribution main capacity and provides the
216 Company with the ability to achieve its purpose of meeting all customer
217 demands for natural gas at all times.

218 **Q WHAT IS THE PRIMARY DRIVER OF EGU'S SYSTEM PEAK DEMAND?**

219 **A** Weather, specifically outside air temperature, is the primary driver of natural gas
220 demand. The Company states that it uses ambient temperature, specifically
221 Heating Degree Days ("HDD"), along with customer-usage patterns to
222 understand temperature-dependent demand, which is extrapolated to a Design
223 Day HDD to represent a statistically derived coldest day.¹² The point is that
224 EGU's system peak demand is driven by weather sensitive customers who use
225 natural gas for space heating, and those customers are largely residential.
226 EGU's system peak demand is not driven by higher load factor customers who
227 use natural gas for process purposes. The allocation of capacity costs must
228 reflect these load characteristics.

¹²EGU's Response to FEA Data Request 2.03. Included as FEA Exhibit 2.01 at 1.

229 **Q ARE THERE OTHER FACTORS THAT CONFIRM THAT SYSTEM PEAK**
230 **DEMAND IS THE CAUSE OF INVESTMENT IN DISTRIBUTION MAIN**
231 **CAPACITY?**

232 **A Yes.** Once this capacity is installed, the costs are fixed and do not change for
233 any amount of gas flowing through the system – whether that is a peak day or
234 any other day. Absent the addition of new customers or a change in system
235 design day requirements, the cost of mains will not change, regardless of
236 changes in annual throughput that result from weather and conservation.

237 Further, consider an example in which EGU serves two customers with
238 the same Design Day Demand requirements from identical distribution mains
239 (i.e., same material, diameter, installed cost). However, one customer's annual
240 throughput is twice as much as the other's. Thus, the demand-related cost to
241 serve each customer is the same. However, each customer would be allocated
242 a different amount of those capacity costs if an annual throughput allocator is
243 used. Specifically, the customer with greater annual throughput (i.e., the higher
244 load factor customer) would be allocated a greater share of capacity costs than
245 the other customer. The use of a throughput allocator effectively penalizes the
246 higher load factor customer for its more efficient utilization of the installed
247 distribution main capacity. This is contrary to the objective of setting rates based
248 on sound cost causation principles.

249 **Q WHAT IS YOUR ISSUE WITH THE COMPANY’S USE OF A P&A**
250 **ALLOCATOR?**

251 A The “Peak” component of the P&A allocator reflects each class’s contribution to
252 system peak day demand (i.e., Design Day Demand); however, as stated
253 above, by using both peak day demand and annual throughput (i.e., average
254 demand) a double counting of average demand occurs.

255 **V. RECOMMENDED MODIFICATIONS TO EGU’S CCOS**

256 **Q HOW DO THE RESULTS OF YOUR PROPOSED CCOS STUDY COMPARE**
257 **TO THE RESULTS OF DEU’S PROPOSED CCOS STUDY?**

258 A As shown in Table1 below, instead of the large increase for the TSL class as
259 proposed by the Company, my CCOS study indicates that the TSL class should
260 actually receive a rate decrease. Because the Company’s CCOS study
261 allocates main costs using a P&A allocator, which results in the double counting
262 of demand described in my testimony above, larger high load factor customer
263 classes are allocated a higher percentage of main costs.

TABLE 1**Class Cost of Service Study Comparison**

Rate Class	EGU Proposed¹			FEA Proposed²		
	Present Non-Gas Revenues	Proposed Increase/ (Decrease)	Percent Increase/ Decrease	Present Non-Gas Revenues	Proposed Increase/ (Decrease)	Percent Increase/ Decrease
	(1)	(2)	(3)	(4)	(5)	(6)
GS	\$485,786,552	\$83,777,557	17.25%	\$486,002,362	\$98,966,646	20.36%
FS	3,731,722	532,828	14.28%	3,723,921	(111,025)	-2.98%
IS	199,664	126,397	63.31%	199,458	101,567	50.92%
TSS	13,697,511	4,926,859	35.97%	13,699,771	4,992,201	36.44%
TSM	18,005,322	5,106,475	28.36%	17,946,455	650,138	3.62%
TSL	21,680,507	5,683,462	26.21%	21,556,498	(3,091,550)	-14.34%
TBF	9,703,971	13,680,054	140.97%	9,677,620	12,393,486	128.06%
NGV	1,673,992	836,117	49.95%	1,673,156	768,287	45.92%
Total	\$554,479,240	\$114,669,749	20.68%	\$554,479,240	\$114,669,749	20.68%

Sources:

¹EGU Exhibit 5.14.²FEA Recommended COS Workpaper.

264 **Q PLEASE DESCRIBE YOUR RECOMMENDED CHANGE TO THE**
 265 **COMPANY'S P&A ALLOCATOR.**

266 **A** I recommend replacing the Company's Peak Demand component with a
 267 calculation of excess demand. That is, each class's contribution to Design Day
 268 Demand in excess of its respective class's average demand would replace the
 269 Company's Peak Demand component.

270 **Q YOU STATED EARLIER IN YOUR TESTIMONY THAT THE CCOS SHOULD**
271 **FOLLOW COST CAUSATION. HOW WOULD REPLACING THE**
272 **COMPANY'S PEAK DEMAND COMPONENT WITH EXCESS DEMAND**
273 **ACCOMPLISH THIS GOAL?**

274 **A My proposed change more closely aligns the Company's CCOS with cost**
275 **causation in two critical ways: first, it removes the inherent flaw of double**
276 **counting average demand which exists in the Company's P&A method; second,**
277 **it allows for a greater assignment of cost to classes with weather-sensitive**
278 **demands by capturing the excess demand in the distribution allocator. As**
279 **stated above, the primary cause of Design Day Demand is outside**
280 **temperatures. Capturing classes' contributions to the excess capacity held in**
281 **reserve to meet the demand of weather-sensitive loads which spike on the**
282 **system peak day better reflects cost causation.**

283 **Q YOU MENTIONED THAT THE P&A METHOD DOUBLE COUNTS AVERAGE**
284 **DEMAND. CAN YOU PLEASE ILLUSTRATE THIS?**

285 **A Yes. Average Demand is counted twice in the cost allocation: once in the**
286 **Average Demand component and again in the Peak Demand component. The**
287 **impact of using the P&A method to allocate distribution main and regulator**
288 **station equipment costs is the over-allocation of capacity costs to high-load**
289 **factor customers. This is represented graphically, below, in Diagram 1. The**
290 **Average Demand (Factor 1) is weighted by the system Load Factor ("LF"). Peak**
291 **Demand (Factor 2) is weighted by (1 – LF). The two weighted demands are**

292 added together to arrive at the P&A allocation factor. As a result, arithmetically,
293 Average Demand receives a full weight of 1, while demand in excess of the
294 average is weighted less than 1 (i.e., by $(1 - LF)$).

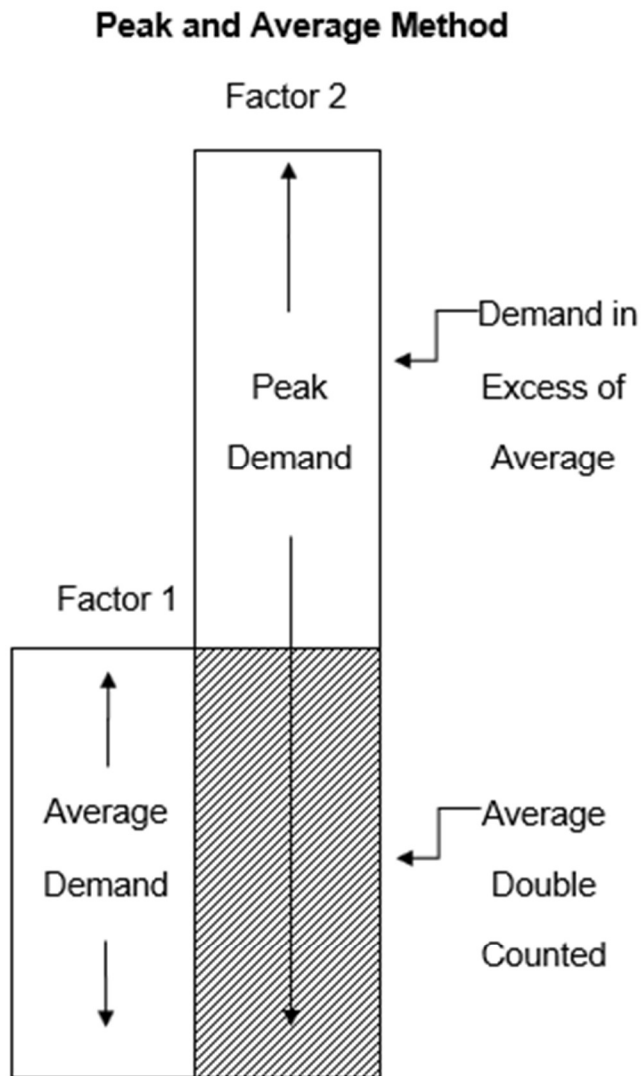


Diagram 1

295 Diagram 1 illustrates the two steps in the process of calculating the P&A factors,
296 the first of which is to determine the Average Demand component. The double
297 counting of Average Demand occurs in the next step of the process, where each
298 class's contribution to the system's Peak Demand is determined. In this second
299 step, the P&A method considers the entire Peak Demand, including the Average
300 Demand.

301 **Q DOES YOUR RECOMMENDED METHOD ASSIGN CAPACITY COSTS TO**
302 **CUSTOMERS IN A MANNER THAT REFLECTS HOW THE SYSTEM**
303 **OPERATES TO PROVIDE SAFE, RELIABLE DELIVERY OF NATURAL GAS**
304 **EVERY DAY OF THE YEAR?**

305 **A** Yes. The Company incurs the cost of mains to meet the aggregate demand of
306 its customers on the expected day of its greatest system demand. The
307 Company's calculation of Design Day Peak Demand is primarily driven by
308 weather-sensitive customer loads on the statistically derived coldest day of the
309 year. Through the use of the excess demand component of the allocator, my
310 recommended method assigns greater cost responsibility to gas deliveries that
311 are more variable due to weather sensitivity or other factors. Relative to the
312 P&A method, my method is more reflective of cost causation on EGU's system,
313 as the excess distribution main capacity is held in reserve to meet the demand
314 of weather-sensitive loads that spike on a peak day.

315 **Q DOES YOUR DISTRIBUTION ALLOCATION METHOD PRODUCE FAIR AND**
316 **REASONABLE RESULTS?**

317 A Yes. Relative to the P&A method, my method more closely reflects how the
318 system is designed and used. Thus, the results are fair and reasonable, and
319 more accurately reflect cost causation on EGU's gas system.

320 **Q DO YOU HAVE ANY OTHER RECOMMENDATIONS WITH RESPECT TO**
321 **THE CCOS?**

322 A Yes. For compressors and regulator facilities, reviewing the Company's CCOS
323 study provided as EGU Exhibit 5.14, tab "COS Detail," the Company is also
324 proposing to allocate these costs on the basis of the P&A method. Compressors
325 and regulators are sized to accommodate the peak day demands of the
326 customers on the distribution mains. Therefore, these facilities' costs should
327 also be allocated across rate classes on the basis of my Excess Design Day
328 Demand and throughput allocator.

329 The Company has allocated these costs on the basis of the P&A method.
330 However, I propose to allocate them on the basis of Excess Design Day
331 Demand and throughput. These costs are also incurred to meet system Design
332 Day Demand and should be allocated to rate classes in a manner which best
333 reflects cost causation.

334 Compressor stations and regulators are sized based on the size of mains
335 and the demands on the system. As such, this equipment is designed to meet
336 the peak day demands of the customers on it. If customers' demands vary from

peak day, the size of this equipment does not change throughout the year, but rather, is held in reserve for each customer until they need the compressor or regulator capacity on the Company's peak day demands. For these reasons, this equipment is sized and engineered in order to support the peak day demands of the customers connected to the distribution system.

Allocating this equipment on the basis of Excess Design Day Demand and throughput is also consistent with cost causation. The NARUC Manual identifies distribution costs to include distribution mains, compressors, and regulators.¹³ As these sets of equipment fall into the same category of accounts, as well as design, as the distribution system, they should be allocated to classes on the same basis to maintain stable price signals to customers and achieve reasonable returns on investment to the Company.

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS WITH RESPECT TO CAPACITY COST ALLOCATION IN THE COMPANY'S CCOS STUDY.

A The evidence provided by EGU makes clear that Design Day Demand, driven by outside temperatures, is the load characteristic that drives investment in distribution capacity to provide safe, reliable firm service to customers on the peak day and all other days throughout the year. However, the Company's use of a P&A allocator creates a double counting of the average demand, creating a mismatch between cost causation and allocation.

¹³Gas Distribution Rate Design Manual, NARUC Staff Subcommittee on Gas, June 1989, at 21-24.

My recommended method, replacing the peak component of the distribution allocator with a calculation of excess Design Day Demand, removes this double counting of the average demand and is more accurate and reasonable than the P&A method for the reasons I have described. Therefore, I recommend the Commission adopt my CCOS using my revised allocation method for large-diameter IHP mains, feeder mains, compressor station equipment, and regulation station equipment, as represented in Table 1.

VI. CLASS REVENUE SPREAD

Q HOW IS THE CLASS COST OF SERVICE STUDY USED TO ALLOCATE THE REVENUE DEFICIENCY IN THIS CASE ACROSS RATE CLASSES?

A The CCOS study is used to measure the increase to each rate class needed to move rates to cost of service. The movement to CCOS should be limited so that it is gradual and ensures that no specific rate class is getting an excessive increase in this case.

Q HOW IS THE COMPANY PROPOSING TO SPREAD THE REVENUE DEFICIENCY ACROSS RATE CLASSES IN THIS CASE?

A The Company's proposed revenue spread allocates part of the distribution system, specifically large-diameter IHP mains and feeder mains, on a P&A allocator. Additionally, there are subsidies included in the CCOS for the TBF

and NGV classes.¹⁴ The TBF class subsidy is a long-standing subsidy in place to prevent harm to remaining classes if the TBF classes were to leave EGU's system.¹⁵ The Company states that the NGV subsidy is necessary due to decreasing usage since the removal of the previous subsidy in 2013.¹⁶ This subsidy is allowable given the subsidy is both in the public interest, and just and reasonable.¹⁷ EGU also states that it is attempting to sell a portion of its Utah NGV stations at this time.¹⁸ The FEA is not challenging the NGV subsidy for this case; however, if the NGV stations remain on EGU's system, the Commission should require EGU to produce evidence the subsidy is in fact in the best interest of the public, i.e., whether this subsidy needed to keep NGV customers on EGU's system in order to prevent a greater harm to the remaining rate payers on EGU's system which would result from the departure of customers from the NGV class.

Q IS THE COMPANY'S PROPOSED SPREAD REASONABLE?

A No. As noted above, the Company's CCOS study is flawed by use of the P&A allocator. I recommend my revised CCOS be used to allocate the revenue deficiency across rate classes.

¹⁴ Direct Testimony of Austin Summers at 11.

¹⁵ *Id.*

¹⁶ Direct Testimony of Austin Summers at 10.

¹⁷ *Id.*

¹⁸ *Id.*

393 **Q HAVE YOU DEVELOPED YOUR OWN CLASS REVENUE ALLOCATION OF**
 394 **THE COMPANY'S REQUESTED RATE INCREASE BASED ON THE**
 395 **RESULTS OF YOUR CCOS STUDY?**

396 **A** Yes. My proposed class revenue allocation is guided by my proposed CCOS
 397 study and is shown in the Table 2 below:

TABLE 2								
Class Revenue Allocation								
(EGU vs FEA)								
Rate Class	Present Non-Gas Revenues	EGU Proposed¹			Present Non-Gas Revenues	FEA Proposed²		
		Proposed Increase/ (Decrease)	Percent Increase/ Decrease	Increase Factor		Proposed Increase/ (Decrease)	Percent Increase/ Decrease	Increase Factor
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
GS	\$485,786,552	\$91,870,108	18.91%	0.9	\$486,002,362	\$106,430,248	21.90%	1.1
FS	3,731,722	630,331	16.89%	0.8	3,723,921	0	0.00%	0.0
IS	199,664	131,400	65.81%	3.2	199,458	61,874	31.02%	1.5
TSS	13,697,511	5,419,397	39.56%	1.9	13,699,771	4,249,796	31.02%	1.5
TSM	18,005,322	5,740,083	31.88%	1.5	17,946,455	925,745	5.16%	0.2
TSL	21,680,507	6,593,746	30.41%	1.5	21,556,498	0	0.00%	0.0
TBF	9,703,971	4,341,870	44.74%	2.2	9,677,620	3,002,088	31.02%	1.5
NGV	1,673,992	(57,185)	-3.42%	(0.2)	1,673,156	0	0.00%	0.0
Total	\$554,479,240	\$114,669,749	20.68%	1.0	\$554,479,240	\$114,669,751	20.68%	1.0

Sources:
¹EGU Exhibit 5.14.
²FEA Recommended COS Workpaper.

398 My proposed class revenue allocation is based on the Company's fully
 399 requested revenue requirement. To the extent that the Commission reduces
 400 the Company's requested revenue requirement, I would propose that any
 401 decrease be spread to customer classes on an equal percent basis after my
 402 class revenue allocation is implemented at the Company's fully requested
 403 revenue requirement.

404 **Q HOW DID YOU DEVELOP YOUR CLASS REVENUE ALLOCATION?**

405 A First, I utilized the principle of gradualism and limited classes to no more than
406 1.5 times the system average increase of 31.02%. I then held classes that
407 would get a rate decrease at full cost of service, to no change in current rates,
408 and set the NGV class to no increase. This revenue difference was then
409 allocated to the remaining classes, which either were not at the maximum
410 increase of 1.5x system average, or set to no increase, by their proportion of
411 Present Non-Gas Revenues.

412 **Q WHY DO YOU BELIEVE YOUR PROPOSED CLASS REVENUE**
413 **ALLOCATION IS REASONABLE?**

414 A Based on the results of my CCOS study, the TSL class and FS classes should
415 actually get a rate decrease as opposed to the Company's proposed 30.41%
416 and 16.89% increases, respectively. My proposed revenue allocation set these
417 classes at no increase. By mitigating the maximum increase for remaining
418 classes to 1.5x the system average, customers are prevented from experiencing
419 rate shock which could have negative consequences within the classes, and for
420 the system as a whole. As a result, my class revenue allocation is more than
421 fair.

422 **Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

423 A Yes, it does.

Qualifications of Matthew P. Smith

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Matthew P. Smith. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a Consultant in the field of public utility regulation with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A In 2017, I received a Bachelor of Science Degree in Economics from Southern Illinois University.

In May of 2018, I accepted an Analyst position with Brubaker & Associates, Inc. ("BAI"). I was promoted to Senior Analyst in 2021, and in 2023 I was promoted to Consultant. During my employment at BAI I have performed detailed analysis on a variety of subjects within the scope of electric, natural gas, and water regulatory proceedings. This analysis includes, but is not limited to, the following: Cost of Service Studies ("COSS"), Return on Equity ("ROE"), Rate Design, and Resource Adequacy issues. I have also been engaged in the evaluation of Request for Proposals ("RFP") responses, the creation of regional electric market price forecast models, and load forecast models for industrial energy users in the electric and natural gas fields. I have sponsored testimony

1 on cost of service, and other issues, before the California State Regulatory
2 Commission and the Florida Public Service Commission.

3 BAI was formed in April 1995. BAI and its predecessor firm have
4 participated in more than 700 regulatory proceedings in 40 states and Canada.

5 BAI provides consulting services in the economic, technical, accounting,
6 and financial aspects of public utility rates and in the acquisition of utility and
7 energy services through RFPs and negotiations, in both regulated and
8 unregulated markets. Our clients include large industrial and institutional
9 customers, state regulatory agencies, and some utilities. We also prepare
10 special studies and reports, forecasts, surveys and siting studies, and present
11 seminars on utility-related issues.

12 In general, we are engaged in energy and regulatory consulting,
13 economic analysis and contract negotiation. In addition to our main office in St.
14 Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville,
15 Kentucky and Phoenix, Arizona.

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Docket No. 25-057-06
FEA Data Request No. 2.03
Requested by the Federal Executive Agency
Date of EGU Response: September 2, 2025

FEA 2.03: Please provide a narrative as to how the Company designs the capacity of its distribution main system to meet the peak natural gas demand of its customers.

Answer: The Company designs the capacity of its distribution main system to meet peak natural gas demand by leveraging a combination of historic customer usage data and ambient temperature metrics, specifically Heating Degree Days (HDD). Customer usage patterns are analyzed and correlated with HDD values to understand temperature-dependent demand. This data is then extrapolated to a Design Day HDD, which represents a statistically derived coldest day based on decades of historical temperature records.

In addition to temperature-driven demand, the Company incorporates firm contract demands from transportation customers into the Design Day forecast. These combined demand projections are used to model the distribution system using hydraulic modeling software, which evaluates system pressures, flows, and velocities across the entire network.

The modeling process also includes gas supply inputs from upstream transmission partners to ensure a comprehensive analysis. Based on the results of this annual peak day design model, the Company identifies and recommends system improvements to maintain reliability and meet customer needs during peak demand conditions.

Prepared by: Jeff Roberts, Supervisor Gas Distribution Engineering
Jordan Parks, Regulatory Analyst

Docket No. 25-057-06
FEA Data Request No. 2.04
Requested by the Federal Executive Agency
Date of EGU Response: September 2, 2025

FEA 2.04: Does the Company use the Design Day Demand of its customers to design the capacity of its distribution main system? Please explain your response.

Answer: Yes. Refer to the Company's response to FEA 2.03.

Prepared by: Jeff Roberts, Supervisor Gas Distribution Engineering
Jordan Parks, Regulatory Analyst

Docket No. 25-057-06
FEA Data Request No. 2.05
Requested by the Federal Executive Agency
Date of EGU Response: September 2, 2025

FEA 2.05: Does the Company use the number of customers on its system to design its distribution main system? Please explain your response.

Answer: System design is based off temperature and contract-dependent demand on a design day. The number of customers is not an influential part of the design process.

Prepared by: Jeff Roberts, Supervisor Gas Distribution Engineering
Jordan Parks, Regulatory Analyst

Docket No. 25-057-06
FEA Data Request No. 2.06
Requested by the Federal Executive Agency
Date of EGU Response: September 2, 2025

FEA 2.06: Does the Company use the system load factor and/or class load factors to design the capacity of its distribution main system? Please explain your response.

- a. Please provide an estimate of the variation of capacity factor on the Company's transmission main, seasonally, throughout the year.

Answer: No. The Company does not use system load factor and/or class load factors to design the capacity of the distribution main system. The Company is not familiar with the term 'Capacity Factor' and does not use it to design the distribution main system.

Prepared by: Jeff Roberts, Supervisor Gas Distribution Engineering
Jordan Parks, Regulatory Analyst

Docket No. 25-057-06
FEA Data Request No. 2.08
Requested by the Federal Executive Agency
Date of EGU Response: September 2, 2025

FEA 2.08: Does the Company use the total usage of its system to design the capacity of its distribution main system? Please explain your response.

Answer: No. The Company does not use the total actual usage to design the capacity of the distribution main system. See response to FEA 2.03 for how the Company designs the distribution main system.

Prepared by: Jeff Roberts, Supervisor Gas Distribution Engineering
Jordan Parks, Regulatory Analyst

Docket No. 25-057-06
FEA Data Request No. 2.09
Requested by the Federal Executive Agency
Date of EGU Response: September 2, 2025

FEA 2.09: Does the Company agree that the system of mains must have enough capacity to meet the expected Design Day Demand of its customers? Please explain your response.

Answer: Yes. Each year, the hydraulic model results are used to identify resultant modeled pressures in Design Day conditions and those results are used to report the adequacy of the system to meet expected Design Day demand. See FEA 2.03.

Prepared by: Jeff Roberts, Supervisor Gas Distribution Engineering
Jordan Parks, Regulatory Analyst

Enbridge Gas Utah
Utah - DEC 2026 Adjusted Avg Results CET
12 Months Ended : Dec-2026

Enbridge Gas Utah
Docket No. 25-057-06
EGU Exhibit 4.07
Page 2 of 2

COST OF SERVICE SUMMARY AND ALLOCATIONS TO RATE CLASSES

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Description		Utah Jurisdiction DNG Related	Allocations to Rate Classes		IS	TSS	TSM	TSL	TBF	NGV
			GS	FS						
Current Revenue Analysis @ 4.94%										
1	Annual Revenue before Deficiency	554,479,240	486,002,362	3,723,921	199,458	13,699,771	17,946,455	21,556,498	9,677,620	1,673,156
2	Return on Rate Base	4.94%	4.98%	8.08%	1.93%	3.25%	7.04%	10.53%	-1.34%	4.54%
3	Increase (Decrease) to equal ROR	-	885,099	(651,600)	31,795	1,099,234	(3,303,184)	(7,851,557)	8,230,011	1,560,202
4	Revenue Neutral Spread	554,479,240	486,887,461	3,072,321	231,252	14,799,005	14,643,271	13,704,942	17,907,631	3,233,358
5	Percentage Change from Current Revenues	0.0%	0.2%	-17.5%	15.9%	8.0%	-18.4%	-36.4%	85.0%	93.2%
6	Rate of Return Index	1.00	1.01	1.64	0.39	0.66	1.43	2.13	(0.27)	0.92
Proposed Revenue Analysis @ 7.61%										
7	Annual Revenue before Deficiency	554,479,240	486,002,362	3,723,921	199,458	13,699,771	17,946,455	21,556,498	9,677,620	1,673,156
8	Deficiency	114,669,749	98,966,646	(111,025)	101,567	4,992,201	650,138	(3,091,550)	12,393,486	768,287
9	COS Adjustment TBF	0	0	0	0	0	0	0	0	0
10	COS Adjustment NGV	0	0	0	0	0	0	0	0	0
11	General Related Revenue Class Allocation	(12,504,033)	(11,249,109)	(57,828)	(3,781)	(263,618)	(303,132)	(336,861)	(275,860)	(13,843)
12	Net Cost of Service Collected in Rates	656,644,957	573,719,899	3,555,068	297,244	18,428,354	18,293,461	18,128,087	21,795,245	2,427,600
13	Increase (Decrease) to equal allowed ROR	114,669,749	98,966,646	(111,025)	101,567	4,992,201	650,138	(3,091,550)	12,393,486	768,287
14	Percentage Change from Current Revenues	20.68%	20.36%	-2.98%	50.92%	36.44%	3.62%	-14.34%	128.06%	45.92%