

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO**

PROCEEDING NO. 19R-0703GPS

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IN THE MATTER OF THE PROPOSED RULES REGULATING PIPELINE OPERATORS  
AND GAS PIPELINE SAFETY, 4 CODE OF COLORADO REGULATIONS 723-11.

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**RECOMMENDED DECISION OF  
ADMINISTRATIVE LAW JUDGE  
CONOR F. FARLEY  
ADOPTING RULES**

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Mailed Date: November 4, 2020

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**I. STATEMENT**

**A. Background**

1. The Colorado Public Utilities Commission issued Decision No. C19-0983, which was a Notice of Proposed Rulemaking (NOPR) to amend the Rules Regulating Pipeline Operators and Gas Pipeline Safety (Pipeline Safety Rules) on December 9, 2019. The NOPR initiated this proceeding. The NOPR proposed significant changes to the Pipeline Safety Rules, including moving the Pipeline Safety Rules from their present location within the Gas Utilities and Pipeline Operator Rules at 4 *Code of Colorado Regulations* (CCR) 723-4, to a new, standalone Part 11, 4 CCR, 723-11. The NOPR described the proposed changes in detail and the justifications therefor, attached a clean copy of the Rules and a version in legislative (*i.e.*, strikeout/underline) format (Initial Proposed Rules), established deadlines of January 17, 2020 and January 31, 2020 for initial comments and reply comments concerning the Initial Proposed Rules, respectively, and scheduled a hearing for February 10, 2020 at 9:00 a.m. for oral comments regarding the Initial Proposed Rules. The NOPR also referred this proceeding to an Administrative Law Judge (ALJ). The proceeding was subsequently assigned to the undersigned ALJ.

2. The American Petroleum Institute (API); Atmos Energy Corporation (Atmos); Black Hills Colorado Gas, Inc. and Rocky Mountain Natural Gas LLC (Black Hills);, Colorado Natural Gas, Inc. (CNG); the Colorado Office of Consumer Counsel (OCC);, the Colorado Oil

and Gas Association (COGA); the Colorado Oil and Gas Conservation Commission; Public Service Company of Colorado (PSCo); and SP Pipeline Services Inc. (SP Pipeline) submitted initial comments and/or reply comments by the deadlines specified in the NOPR.

3. At 9:00 a.m. on February 10, 2020, the ALJ held the hearing noticed in the NOPR. The ALJ discussed several of the Initial Proposed Rules with the participants at the hearing. Based on the input of the commenters at the hearing, the ALJ continued the hearing to allow the commenters to engage in a stakeholder process to address and revise the Initial Proposed Rules, submit revised proposed rules (Revised Proposed Rules) to the Commission, comment on those Revised Proposed Rules in writing, and schedule a continued hearing to receive additional oral comments regarding the Revised Proposed Rules.

4. In Decision No. R20-0168-I issued March 12, 2020, the ALJ established the schedule for the informal stakeholder process. The Decision set May 15, 2020 as the deadline to file a notice that summarized the stakeholder process with attachments thereto consisting of the Revised Proposed Rules, and June 5, 2020 and June 19, 2020 as the deadlines for comments and response comments, respectively, regarding the Revised Proposed Rules.

5. On May 18, 2020, the ALJ issued Decision No. R20-0374-I that granted an informal request to continue: (a) the deadline to submit the notice and attachments referenced in Decision No. R20-0168-I to June 1, 2020; and (b) the deadlines for comments and response comments concerning the Revised Proposed Rules to June 15 and 29, 2020, respectively.

6. On June 1, 2020, Joe Molloy, the Chief of the Commission's Pipeline Safety Program filed the Notice of Draft Rule Stakeholder Workshop Process and Results (Notice) and copies of the Revised Proposed Rules in clean and legislative formats.

7. COGA, Colorado Springs Utilities, API, and CNG filed initial comments regarding the Revised Proposed Rules from June 12 to 15, 2020. No party filed response comments.

8. On July 7, 2020, the ALJ issued Decision No. R20-0492-I that converted the in-person continued public comment hearing into a remote continued public comment hearing.

9. On July 10, 2020, the ALJ held the remote continued public comment hearing. During the hearing, some participants expressed an interest in having a last opportunity to provide comments concerning the Revised Proposed Rules. In particular, some participants requested the opportunity to provide further comment regarding a proposal to allow an operator to request dismissal of a Notice of Probable Violation (NPV) to Proposed Rule 11505(c)(II)(a), rather than “revocation” of the NPV, as proposed by COGA in its comments filed on June 12, 2020. Some participants also requested the opportunity to provide further comments concerning whether a process for requesting and/or addressing “revocation” or “dismissal” of an NPV should be specified in the rules.

10. On July 14, 2020, the ALJ issued Decision No. R20-0507-I that established the deadline of July 24, 2020 for any final comments regarding the Revised Proposed Rules.

11. On July 15, 2020, PSCo filed its Final Comments.

12. Being fully advised in this matter, the ALJ now transmits to the Commission the record in this proceeding along with a written recommended decision in accordance with § 40-6-109, C.R.S.

## II. DISCUSSION

### A. Introduction

13. In rendering this Decision, the ALJ has carefully reviewed and considered all the comments filed in this Proceeding and provided at the public comment hearing, even if this Decision does not specifically address every comment made, or every nuance of each comment.

### B. Stakeholder Process

14. As noted, the stakeholder process took place from approximately late February through May 2020. The attendees at the first public comment hearing were invited to participate in the stakeholder process, but the process was not closed to new participants. Initially, API created a working draft of the Initial Proposed Rules and the comments/proposed changes submitted in writing before the February 10, 2020 public comment hearing and the comments made at that hearing.

15. The stakeholder participants agreed to divide the Initial Proposed Rules with comments/proposed changes into the following four groups: (a) Initial Proposed Rules 11000 to 11099; (b) Initial Proposed Rules 11100 to 11399; (c) Initial Proposed Rules 11400 to 11509; and (d) Initial Proposed Rules 11500 to 11509. The participants also agreed to hold four meetings addressing these groups of rules in succession. The four meetings were held once a week from April 24, 2020 to May 20, 2020. At the end of this process, the participants agreed to hold a fifth meeting to review the changes to Initial Proposed Rules 11500 to 11509.

16. Twenty-seven stakeholder participants attended the first meeting, and an average of 25 participants attended the subsequent meetings. According to the Notice, API, Atmos, Black Hills, CNG, OCC, COGA, PSCo, and SP Pipeline were “strong repeat commenters and

contributors” to the stakeholder process.<sup>1</sup> The stakeholder process resulted in “numerous significant changes” to the Initial Proposed Rules. The Notice stated that the stakeholder participants supported the changes and the final rules attached to the Notice.

**C. Written Comments Concerning the Revised Proposed Rules**

17. COGA and Colorado Springs Utilities filed substantive comments regarding the Revised Proposed Rules. In its comments, COGA recommended adding “revocation” to Rule 11504(c)(II)(A) as one of the actions that operators may request the Commission undertake with respect to a NPV. For its part, Colorado Springs Utilities proposed: (a) corrections to several typographical errors; (b) reinserting into Rule 11001 the definition of “Small operator” that was included in the redlined, but omitted from the clean, rules filed with the Notice; and (c) adding to Rule 11001 a definition of “confirmed discovery” that is the same as the definition of that term in 49 *Code of Federal Regulations* (C.F.R.) § 191.3. No party filed response comments opposing or offering revisions to the comments of COGA and Colorado Springs Utilities.

**D. Public Comment Hearing**

18. The stakeholder participants attended the public comment hearing on July 10, 2020. No participant opposed the changes proposed by COGA and Colorado Springs Utilities. However, a consensus emerged to replace “revocation” with “dismissal” in COGA’s proposal. Specifically, the stakeholders, including COGA, agreed that “dismissal,” rather than “revocation,” should be added to Rule 11504(c)(II)(A) as one of the actions that operators may

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<sup>1</sup> Notice at ¶ 7.

request the Commission undertake with respect to an NPV. In addition, the question was raised as to whether the procedure by which an NPV is “revoked” by the Commission must be specified in the rules. However, this question was eliminated from consideration once the stakeholders agreed to replace revocation with dismissal in Rule 11504(c)(II)(A), as the procedure involving dismissals is well-known to the Commission.

### **E. Post-Hearing Final Comments**

19. PSCo filed post-hearing comments to reiterate that it supports replacing “revocation” with “dismissal” in the list of actions specified in Rule 11504(c)(II)(A) as one of the actions that operators may request the Commission undertake with respect to an NPV. PSCo also stated that it would support specifying a process in Rule 11504(c)(II) or (III) by which a letter would be filed in the proceeding stating that the Commission dismisses an NPV. However, PSCo also stated that it “does not feel strongly that the process needs to be specifically expressed in the Pipeline Safety Rules of 4 CCR 723-11.”<sup>2</sup>

### **F. Analysis**

#### **1. Typographical Errors**

20. The typographical errors identified by Colorado Springs Utilities shall be corrected. In addition, the ALJ has made several other changes to correct other typographical errors and to aid the readability of the Revised Proposed Rules. The ALJ’s intent in making these changes was not to change the meaning of the relevant rules.

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<sup>2</sup> PSCo’s Final Comments at 2.

## 2. Rule 11000

21. The ALJ has added the following underlined text to Revised Proposed Rule 11000(f):

Consistent with § 40-15-107(2)(a), C.R.S., all information, documents, and copies of documents provided in connection with an audit, including any Request for Information from the PSP Chief or PSP Staff, shall be treated as confidential and shall not be made public by the Commission or any other person without prior written consent of the person providing such information, documents, or copies; or pursuant to a court order issued pursuant to § 24-72-204(5), C.R.S. If any such information, document, or copy of a document becomes the basis for, or employed within, an enforcement action pursuant to Rule 11500 et seq., Rules 1100-1103 of the Commission’s Rules of Practice and Procedure shall govern any claim of confidentiality in such proceeding. Any such information, document, or copy of a document that is not treated as, or deemed, confidential or highly confidential in any such proceeding thereafter shall not be treated by the Commission as confidential for any other purpose.

The purpose of the change is to specify that once information obtained through a Request for Information is employed in an enforcement action, Rules 1100 through 1103 of the Rules of Practice and Procedure 4 CCR 723-1, govern confidentiality in that proceeding, not Revised Proposed Rule 11000(f). As such, the burden would be on the operator to assert confidentiality over the information in the enforcement proceeding and, if challenged, establish that the information is entitled to confidential or highly confidential treatment. In addition, if such information is found by the Commission to not be confidential or highly confidential, the presumption accorded by Rule 11000(f) would terminate and the Commission, including the PSP Chief and PSP Staff, would no longer treat the information as confidential.

## 3. Rule 11001

22. The unopposed changes proposed by Colorado Springs Utilities to Rule 11001 shall be adopted. Accordingly, Rule 11001 shall contain the definition of “Small operator” that was included in the redlined, but omitted from the clean version of the rules filed with the



Notice. It will also include a definition of “confirmed discovery” that is the same as the definition of that term in 49 C.F.R. § 191.3.

#### 4. Rules 11010 and 11011

##### a. Rule 11010

23. The ALJ has made the following changes, shown in underline and strikethrough, to Revised Proposed Rule 11010(b):

(a) Consistent with Rule 1304 of the Commission Rules of Practice and Procedure, 4 CCR 723-1, ~~a~~An operator may file a petition seeking a declaratory order ~~to request a resolution of that resolves~~ a controversy or uncertainty regarding any statute, Commission rule, regulation, and/or Commission decision and/or decisions consistent with rule 1304, of the Commission Rules of Practice and Procedure, 4 CCR 723-1. The requestor shall include with each request, at least the following:

(I) the statutory provision(s), Commission rule(s), regulation(s), and/or decision(s) ~~reference~~at issue;

(II) the specific instance or illustration of the ~~rule’s or decision’s~~ application of the statutory provision(s), Commission rule(s), regulation(s), and/or decision(s) ~~requiring interpretation~~that causes the controversy or uncertainty; and

(III) the complete petitioner’s contact information.

(IV) The petition may also include a request for expedited treatment if an interpretation is needed quickly and good cause exists.

(b) Upon receipt of the petition for a declaratory order, the Commission will consider whether to accept the filing consistent with Rule 1304 of the Commission’s Rules of Practice and Procedure, 4 CCR 723-1.

~~(I) If the Commission determines that the requested resolution concerns a Colorado-specific rule or Commission decision that is only technical in nature and no subsequent review by PHSMA is required, the PSP Chief shall advise the Commission that the Commission does not need to accept the petition because no controversy exists. An order declining to accept the petition will clarify the technical matter raised.~~

~~(II) If the Commission determines that the requested resolution concerns a Colorado-specific rule or Commission decision that addresses Commission administration or processes and no subsequent review by~~

~~PHMSA is required, the Commission shall accept the petition in order to resolve the controversy or uncertainty.~~

24. The ALJ made these changes to specify that Rule 1304 of the Commission’s Rules of Practice and Procedure will govern the Commission’s consideration of a petition for declaratory order. The language that the ALJ has modified and deleted risked creating confusion about the standard to be applied to such petitions filed by pipeline operators.

25. The ALJ made the following changes to Revised Proposed Rules 11010(c) and (d):

~~(e) — Any interpretation or rule or decision is effective upon approval by the Commission or the PHMSA Administrator for Pipeline Safety, as applicable.~~

(d) Nothing in these rules prohibits an operator from contacting the PSP Chief or PSP Lead Engineer for informal assistance if no formal action is necessary. Consistent with Rule 1007(d) of the Commission’s Rules of Practice and Procedure, 4 CCR 723-1, opinions expressed ~~Any interpretation or direction provided~~ by the PSP Chief or PSP Lead Engineer do not represent the official views of the Commission, but are designed to aid the public and to facilitate the accomplishment of the Commission’s functions. Nothing communicated by the PSP Chief or PSP Lead Engineer constitutes legal advice. ~~es not constitute a final Commission decision, consistent with the Commission’s Rules of Practice and Procedure 4 CCR 723-1-1007(d).~~

26. The ALJ deleted Revised Proposed Rule 11010(c) because it is unnecessary and thus superfluous. The ALJ’s changes to Revised Proposed Rule 11010(d) make clear that any informal assistance provided by Commission Staff is subject to Commission Rule 1007(d), 4 CCR 723-1. Informal assistance provided by the PSP Chief or PSP Staff is thus not accorded any greater weight than informal assistance provided by any other Commission Staff member.

**b. Rule 11011**

27. The ALJ has made substantial changes to Revised Proposed Rule 11011 to specify that: (a) operators seeking waivers of Commission rules, including requests for waiver or federal regulations incorporated into the Commission’s rules, must file a petition or motion for waiver

pursuant to Commission Rule 1003(b); and (b) the Commission will decide such petitions. The NOPR specified that the proposed rules “are aimed at adding transparency and Commissioner engagement throughout the [Pipeline Safety Program] processes.” Requiring the Commission, and not the PSP Chief, to make decisions on waiver requests better serves those aims.

**c. Rules 11010 and 11011**

28. The ALJ has also made substantial changes to both Rules 11010 and 11011 to specify the process of obtaining a review by the Pipeline and Hazardous Materials Safety Administration (PHMSA), which is an agency of the United States Department of Transportation, of Commission decisions interpreting federal regulations, or granting waivers of such regulations, that are incorporated into the Commission’s rules.<sup>3</sup> Rule 11010 addresses Commission decisions interpreting, among other things, “any . . . Commission rule [or] regulation,” including the federal regulations incorporated into the Commission’s rules. Rule 11011 addresses Commission decisions on requests for waivers from the safety standards in 49 C.F.R. Part 192 that are incorporated into the Commission’s rules. The ALJ’s changes specify that the decision by an ALJ or the Commission interpreting a federal regulation pursuant to Rule 11010, and/or granting a waiver from a federal regulation pursuant to Rule 11011, must be an interim decision.

29. These changes are designed to ensure that parties to Commission proceedings are not required to file exceptions to a Recommended Decision, or an application for rehearing, reargument, or reconsideration (RRR), or for judicial review of a Commission Decision, during the pendency of PHMSA’s review of that Recommended or Commission Decision. Filing and considering exceptions, RRR, and/or judicial review during the pendency of PHMSA’s review of

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<sup>3</sup> See Commission Rule 11008.

a Commission decision would be an inefficient use of the resources of the Commission and the parties to the proceeding in which the Commission's decision issued.<sup>4</sup> The changes do not, however, eliminate the opportunity for parties to file exceptions to a Recommended Decision, or an application for RRR or for judicial review of a Commission Decision, interpreting a federal regulation pursuant to Rule 11010 and/or granting a waiver from a federal regulation pursuant to Rule 11011. Instead, parties can file exceptions, or an application for RRR or for judicial review, once PHMSA's response is incorporated into an ALJ's Recommended Decision or a Commission Decision, respectively.

## 5. Rule 11013

30. The ALJ has made the following change to Revised Proposed Rule 11013(b):

Prior to an inspection or investigation, the PSP Chief or assignee shall notify an operator. Except in emergency situations, ~~t~~The operator shall have an opportunity to respond to the notification prior to the initiation of an inspection or investigation relating to any jurisdictional pipeline facility, including the Facilities subject to inspection include, but are not limited to, an operator's right of way or easement, new and existing piping, valves, and other above ground appurtenances attached to pipes, or, upon request of the PHMSA, an interstate pipeline to determine compliance with 49 U.S.C. §§ 60101 et. seq., with these rules, and/or with applicable Commission orders.

31. The purpose of the change is to place a reasonable limitation on the right of response to an inspection or investigation so the Commission is not impeded from timely addressing an emergency situation that could put the public at risk.

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<sup>4</sup> The changes to Rules 11010 and 11011 are too extensive to show effectively in underlining and strikethrough.

## 6. Rule 11501

32. The ALJ has made two primary sets of changes to this rule. First, the ALJ made the following addition to Revised Proposed Rule 11501(a):

This rule shall apply to violation(s) that would have otherwise been discovered by a prudent operator in the normal course of business. This is the lowest degree of culpability for which operators may be penalized and does not limit the Commission from penalizing operators for higher degrees of culpability.

The ALJ added the underlined sentence to underscore that the preceding sentence does not prohibit the Commission from addressing more culpable conduct:

33. Second, the ALJ has added provisions addressing the Commission's authority to assess doubled or tripled penalties pursuant to § 40-7-113.5(3) and (4), C.R.S. The language specifies the circumstances in which the Commission may assess doubled and tripled penalties. The added provisions are adapted from Rules 3010(f) and (g) and Rule 6019 of the Commission's Electric and Transportation Rules, respectively.<sup>5</sup> The changes make clear when the Commission can exercise its statutory authority to assess double or treble damages and treats pipelines the same as electric utilities and regulated transportation providers.

34. Finally, the ALJ has deleted provisions limiting the Commission's discretion in assessing penalties. As proposed by the parties, Rule 11501(k) and (l) removed the Commission's ability to impose joint liability (and thus joint and several liability) for violations of the rules, or to impose penalties for violations of the Commission's rules "assessed on the operator by the Commission's state or federal regulatory counterparts." The ALJ finds and concludes that these limitations should not be imposed on the authority of the Commission by

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<sup>5</sup> Commission's Rules Regulating Electric Utilities 4 CCR 723-3 and Rules Regulating Transportation by Motor Vehicle 4 CCR 723-6.

rule, particularly given that joint and several liability has been imposed by the Commission in the past<sup>6</sup> and there may be circumstances in the future in which it would be in the public interest for the Commission to pursue penalties for violations that have been the subject of separate actions by federal or other state regulatory authorities. Instead, the concepts embodied in Proposed Rule 11501(k) and (l) should be reserved for argument by operators concerning the appropriate penalty to be imposed in individual compliance proceedings.

### **7. Rule 11502**

35. The ALJ has made changes to Revised Proposed Rule 11502(d) and (e) to specify that service of process, and the resulting notice provided to the recipient, shall be governed by Rule 1205 of the Commission's Rules of Practice and Procedure and § 40-6-108, C.R.S. There is no reason to deviate from these legal requirements that govern all other Commission proceedings.

### **8. Rules 11504 and 11506**

36. The ALJ has deleted Revised Proposed Rules 11504(c)(I)(C) and 11506(c)(I)(C) to eliminate any possible inconsistency between those provisions and newly added Rule 11501(i). Specifically, the deletion removes the ability of an operator to "admit" the NPV or NOA by paying the proposed civil penalty and agreeing to implement the proposed compliance directive, but then state in the written explanation that the circumstances alleged in the NPV or NOA do not constitute a violation of the Commission's rules. The operator could

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<sup>6</sup> See, e.g., Decision No. R10-1216 issued on November 8, 2010 in Proceeding No. 10G-177EC at 12-13 (¶ 61), 14 (Ordering ¶ 5).

later attempt to argue that the Commission does not have the authority to impose double or treble penalties because the operator's statement in the earlier proceeding establishes that it did not "admit" liability in that proceeding. The deletion of Revised Proposed Rules 11504(c)(I)(C) and 11506(c)(I)(C) does not eliminate the ability of an operator to argue that a previous admission of liability in a previous proceeding does not justify the imposition of double or treble damages in a proceeding in which such damages are sought.

37. The ALJ has also added "or dismissal" to the list of actions an operator can request of the Commission in response to an NPV in Revised Proposed Rule 11504(c)(II)(A). COGA requested this change, the Stakeholder Group agreed to it, and no public comment was submitted opposing the change. The ALJ agrees with this option to Rule 11504(c)(II)(A).

## 9. Rule 11507

38. The ALJ has deleted the following portions of Revised Proposed Rule 11507(e) as unnecessary and thus superfluous:

(e) A Commission decision finding that a pipeline facility or a LNG facility is a hazardous facility shall contain ~~the following:~~

~~(I) findings of fact that form the basis for the conclusion that the pipeline facility or the LNG facility is hazardous to life or property;~~

~~(II) a conclusion that the pipeline facility or the LNG facility is a hazardous facility;~~

~~(III) the legal basis for the decision and order;~~

~~(IV) a description of the corrective action required of the operator; and~~

~~(V) the date by which the operator shall complete the ordered corrective action.~~

39. The ALJ also replaced subparagraph (h) as follows:

~~(h) Following issuance of an order of satisfaction, the PSP Chief may issue a NPV pursuant to rule 11504 if information obtained during hazardous facility mitigation indicates that a violation of these rules led to the facility becoming hazardous. PSP Staff may bring a formal complaint seeking the issuance of an HFO and an NPV in the same proceeding, but is not required to do so.~~

The ALJ made this change to specify the full range of the authority of PSP Staff in bringing such actions and to avoid any future argument that PSP Staff is required to bring in a formal complaint requesting the issuance of an HFO and an NPV as separate proceedings. There may be efficiency and other reasons for bringing a consolidated formal complaint and NPV proceeding. The change preserves the ability of the Commission to conduct proceedings in the most efficient way possible.

40. Pursuant to the provisions of § 40-6-109, C.R.S., it is recommended that the Commission adopt the attached rules.

### **III. ORDER**

#### **A. The Commission Orders That:**

1. The Rules Regulating Pipeline Operators and Gas Pipeline Safety, attached to this Recommended Decision are adopted.

2. The Part 4 rules in redline legislative format and in final format are attached to this Recommended Decision as Attachments A and B, respectively. The Part 11 Rules in final format are attached as Attachment C. All three attachments are also available in the Commission's E-Filings system at:

[https://www.dora.state.co.us/pls/efi/EFI.Show\\_Docket?p\\_session\\_id=&p\\_docket\\_id=19R-0703GPS](https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=19R-0703GPS)



3. This Recommended Decision shall be effective on the day it becomes the Decision of the Commission, if that is the case, and is entered as of the date above.

4. As provided by § 40-6-109, C.R.S., copies of this Recommended Decision shall be made available to all parties in the proceeding, who may file exceptions to it.

a) If no exceptions are filed within 20 days after service or within any extended period of time authorized, or unless the decision is stayed by the Commission upon its own motion, the recommended decision shall become the decision of the Commission and subject to the provisions of § 40-6-114, C.R.S.

b) If a party seeks to amend, modify, annul, or reverse basic findings of fact in its exceptions, that party must request and pay for a transcript to be filed, or the parties may stipulate to portions of the transcript according to the procedure stated in § 40-6-113, C.R.S. If no transcript or stipulation is filed, the Commission is bound by the facts set out by the administrative law judge and the parties cannot challenge these facts. This will limit what the Commission can review if exceptions are filed.

5. If exceptions to this Decision are filed, they shall not exceed 30 pages in length, unless the Commission for good cause shown permits this limit to be exceeded.

(S E A L)



THE PUBLIC UTILITIES COMMISSION  
OF THE STATE OF COLORADO

CONOR F. FARLEY

Administrative Law Judge

ATTEST: A TRUE COPY

A handwritten signature in cursive script that reads 'Doug Dean'.

Doug Dean,  
Director

## COLORADO DEPARTMENT OF REGULATORY AGENCIES

### Public Utilities Commission

#### 4 CODE OF COLORADO REGULATIONS (CCR) 723-4

#### PART 4

#### RULES REGULATING GAS UTILITIES ~~AND PIPELINE OPERATORS~~

##### **BASIS, PURPOSE, AND STATUTORY AUTHORITY.**

The basis and purpose of these rules is to set forth rules describing the service to be provided by jurisdictional gas utilities and master meter operators to their customers and describing the manner of regulation over jurisdictional gas utilities, master meter operators, and the services they provide. These rules address a wide variety of subject areas including, but not limited to, service interruption, meter testing and accuracy, safety, customer information, customer deposits, rate schedules and tariffs, discontinuance of service, master meter operations, transportation service, flexible regulation, procedures for administering the Low-Income Energy Assistance Act, gas service low-income program, cost allocation between regulated and unregulated operations, recovery of gas costs, appeals regarding local government land use decisions, and authority of the Commission to impose civil penalties on public utilities. The statutory authority for these rules can be found at §§ 29-20-108, 40-1-103.5, 40-2-108, ~~40-2-115~~, 40-3-102, 40-3-103, 40-3-104.3, 40-3-106, 40-3-111, 40-3-114, 40-3-101, 40-4-101, 40-4-106, 40-4-108, 40-4-109, 40-5-103, 40-7-117, 40-7-113.5, 40-7-116.5; and 40-8.7-105(5), C.R.S.

##### **GENERAL PROVISIONS**

##### **4000. Scope and Applicability.**

(a) Absent a specific statute, rule, or Commission order which provides otherwise, all rules in this Part 4 (the 4000 series) shall apply to all jurisdictional gas utilities, gas master meter operators, ~~and gas pipeline system operators~~ and to all Commission proceedings concerning gas utilities, ~~and~~ gas master meter operators, ~~and gas pipeline safety~~.

(b) The scope and applicability rules regarding appeals of local government land use decisions are as stated in rule 4700.

~~(c) The scope and applicability of rules regarding pipeline safety, which apply to pipeline operators and to those that are subject to other 4000 series rules, are as stated in rule 4900.~~

##### **4001. Definitions.**

The following definitions apply throughout this Part 4, except where a specific rule or statute provides otherwise. In addition to the definitions here, the definitions found in the Public Utilities Law and Part 1 apply to these rules. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply. In the event of a conflict between these definitions and a definition in Part 1, these definitions shall apply.

- (a) "Affiliate" of a utility means a subsidiary of a utility, a parent corporation of a utility, a joint venture organized as a separate corporation or partnership to the extent of the individual utility's involvement with the joint venture, a subsidiary of a parent corporation of a utility or where the utility or the parent corporation has a controlling interest over an entity.
- (b) "Aggregated data" means customer data, alone or in combination with non-customer data, resulting from processing (e.g., average of a group of customers) and/or a compilation of customer data of one or more customers from which and personal information has been removed.
- (c) "Applicant for service" means a person who applies for utility service and who either has taken no previous utility service from that utility or has not taken utility service from that utility within the most recent 30 days.
- (d) "Basis Point" means one-hundredth of a percentage point (100 basis points = 1 percent).
- (e) "Benefit of service" means the use of utility service by each person of legal age who resides at a premises to which service is delivered and who is not registered with the utility as the customer of record.
- (f) "Commission" means the Colorado Public Utilities Commission.
- (g) "Contracted agent" means any person that has contracted with a utility in compliance with rule 4030 to assist in the provision of regulated utility services (e.g., an affiliate or vendor).
- (h) "Cubic foot" means, as the context requires:
  - (I) At Local Pressure Conditions. For the purpose of measuring gas to a customer at local pressure conditions, a cubic foot is that amount of gas which occupies a volume of one cubic foot under the conditions existing in the customer's meter as and where installed. When gas is metered at a pressure in excess of eight inches of water column gauge pressure, a suitable correction factor shall be applied to provide for measurement of gas as if delivered and metered at a pressure of six inches of water column gauge pressure. A utility may also apply appropriate factors to correct local pressure measurement to standard conditions.
  - (II) At Standard Conditions. For all other purposes, including testing gas, a standard cubic foot is that amount of gas at standard conditions which occupies a volume of one cubic foot.
- (i) "Curtailment" means the inability of a transportation customer or a sales customer to receive gas due to a shortage of gas supply.
- (j) "Customer" means any person who is currently receiving utility service. Any person who moves within a utility's service territory and obtains utility service at a new location within 30 days shall be considered a "customer." Unless stated in a particular rule, "customer" applies to any class of customer as defined by the Commission or by utility tariff.

- (k) "Customer data" means customer specific information, excluding personal information as defined in paragraph 1004(x), that is:
  - (I) collected from the gas meter by the utility and stored in its data systems;
  - (II) combined with customer-specific energy usage information on bills issued to the customer for regulated utility service when not publicly or lawfully available to the general public; or
  - (III) about the customer's participation in regulated utility programs, such as renewable energy, demand-side management, load management, or energy efficiency programs.
- (l) "Dekatherm" (Dth) means a measurement of gas commodity heat content. One Dekatherm is the energy equivalent of 1,000,000 British Thermal Units (1 MMBtu).
- (m) "Distribution system" means the piping and associated facilities used to deliver gas to customers, excluding facilities owned by a utility that are classified on the books and records of the utility as production, storage, or transmission facilities.
- (n) "Energy assistance organization" means the nonprofit corporation established for low-income energy assistance pursuant to § 40-8.5-104, C.R.S.
- (o) "Gas" means natural gas; flammable gas; manufactured gas; petroleum or other hydrocarbon gases including propane; or any mixture of gases produced, transmitted, distributed, or furnished by any utility.
- (p) "Informal complaint" means an informal complaint as defined and discussed in the Commission's Rules Regulating Practice and Procedure.
- (q) "Interruption" means a utility's inability to provide transportation to a transportation customer, or its inability to serve a sales customer, due to constraints on the utility's pipeline system.
- (r) "Intrastate transmission pipeline" or "ITP" means generally any person that provides gas transportation service for compensation to or for another person in the State of Colorado using transmission facilities rather than distribution facilities and is exempt from FERC jurisdiction.
- (s) "Local distribution company" (LDC) means any person, other than an interstate pipeline or an intrastate transmission pipeline, engaged in the sale and distribution of gas for end-user consumption. A LDC may also perform transportation services for its end-use customers, for another LDC and/or its end-use customers, as authorized under its effective Colorado jurisdictional tariffs.
- (t) "Local government" means any Colorado county, municipality, city and county, home rule city or town, home rule city and county, or city or town operating under a territorial charter.
- (u) "Local office" means any Colorado office operated by a utility at which persons may make requests to establish or to discontinue utility service. If the utility does not operate an office in Colorado, "local office" means any office operated by a utility at which persons may make requests to establish or to discontinue utility service in Colorado.

- (v) "Main" means a distribution line that serves, or is designed to serve, as a common source of supply for more than one service lateral.
- (w) "Mcf" means 1,000 standard cubic feet.
- (x) "MMBtu" means 1,000,000 British Thermal Units, or one Dekatherm.
- (y) "Non-standard customer data" means all customer data that are not standard customer data.
- (z) "Past due" means the point at which a utility can affect a customer's account for regulated service due to non-payment of charges for regulated service.
- (aa) "Pipeline system" means the piping and associated facilities used in the transmission and/or distribution of gas.
- (bb) "Principal place of business" means the place, in or out of the State of Colorado, where the executive or managing principals who directly oversee the utility's operations in Colorado are located.
- (cc) "Property owner" means the legal owner of government record for a parcel of real property within the service territory of a utility. A utility may rely upon the records of a county clerk for the county within which a parcel of real property is located to determine ownership of government record.
- (dd) "Regulated charges" means charges billed by a utility to a customer if such charges are approved by the Commission, presented on a tariff sheet, and/or contained in a tariff of the utility.
- (ee) "Sales customer" means a person who receives sales service from a utility.
- (ff) "Sales service" means a bundled gas utility service in which the utility both purchases gas commodity for resale to the customer and delivers the gas to the customer.
- (gg) "Security" includes any stock, bond, note, or other evidence of indebtedness.
- (hh) "Service lateral" means that part of a distribution system from the utility's main to the entrance to a customer's physical location.
- (ii) "Standard conditions" means gas at a temperature of 60 degrees Fahrenheit and subject to an absolute pressure equal to 14.73 pounds per square inch absolute.
- (jj) "Standard customer data" means customer data maintained by a utility in its systems in the ordinary course of business.
- (kk) "Standby capacity" means the maximum daily volumetric amount of capacity reserved in the utility's system for use by a transportation customer, if the customer purchased optional standby service.
- (ll) "Standby supply" means the daily volumetric amount of gas reserved by a utility for the use by a transportation customer should that customer's supply fail, if the customer purchased optional standby service.

- (mm) "Third party" means a person who is not the customer, an agent of the customer who has been designated by the customer with the utility and is acting on the customer's behalf, a regulated utility serving the customer, or a contracted agent of the utility.
- (nn) "Transportation" means the exchange, forward-haul, backhaul, flow reversal, or displacement of gas between a utility and a transportation customer through a pipeline system.
- (oo) "Transportation customer" means a person who, by signing a gas transportation agreement, elects to subscribe to gas transportation service offered by a utility.
- (pp) "Unique identifier" means customer's name, mailing address, telephone number, or email address that is displayed on a bill.
- (qq) "Unregulated charges" means charges that are billed by a utility to a customer and that are not regulated or approved by the Commission, are not contained in a tariff, and are for service or merchandise not required as a condition of receiving regulated utility service.
- (rr) "Upstream pipeline" means either a natural gas pipeline or a LDC that provides gas to a LDC.
- (ss) "Utility" means a public utility as defined in § 40-1-103, C.R.S., providing sales service or transportation service (or both) in Colorado. This term includes both an ITP and a LDC.
- (tt) "Utility service" or "service" means a service offering of a utility, which service offering is regulated by the Commission.
- (uu) "Whole building data" means the sum of the monthly gas use for either all service connections at a building on a parcel of real property or all buildings on a parcel of real property.

**4002. Applications.**

- (a) Any person may seek Commission action regarding any of the following matters through the filing of an appropriate application to request a(n):
  - (I) issuance or extension of a certificate of public convenience and necessity for a franchise, as provided in rule 4100;
  - (II) issuance or extension of a certificate of public convenience and necessity for service territory, as provided in rule 4101;
  - (III) issuance of a certificate of public convenience and necessity for construction of facilities, as provided in rule 4102;
  - (IV) amendment of a certificate of public convenience and necessity to change, extend, curtail, abandon, or discontinue any service or facility, as provided in rule 4103;
  - (V) transfer a certificate of public convenience and necessity, to obtain a controlling interest in any utility, to transfer assets within the jurisdiction of the Commission or stock, or to merge a utility with another entity, as provided in rule 4104;

- (VI) approval of the issuance or assumption of any security, or to create a lien pursuant to § 40-1-104, as provided in rule 4105;
  - (VII) flexible regulatory treatment to provide service without reference to tariffs, as provided in rule 4106;
  - (VIII) amendment of a tariff on less than statutory notice, as provided in rule 4109;
  - (IX) approval of a meter sampling program, as provided in rule 4304;
  - (X) approval of a refund plan, as provided in rule 4410;
  - (XI) approval of a Low-Income Energy Assistance Plan, as provided in rule 4411;
  - (XII) approval of a cost assignment and allocation manual, as provided in rule 4503;
  - (XIII) appeal of a local government land use decision, as provided in rule 4703; or
  - (XIV) any other matter not specifically described in this rule, unless such matter is required to be submitted as a petition under rule 1304, as a motion, or as some other specific type of submittal.
- (b) In addition to the requirements of specific rules, all applications shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
- (I) the name and address of the applying utility;
  - (II) the name(s) under which the applying utility is, or will be, providing service in Colorado;
  - (III) the name, address, telephone number, and e-mail address of the applying utility's representative to whom all inquiries concerning the application should be made;
  - (IV) a statement that the applying utility agrees to answer all questions propounded by the Commission or Commission staff concerning the application;
  - (V) a statement that the applying utility shall permit the Commission or Commission staff to inspect the applying utility's books and records as part of the investigation into the application;
  - (VI) a statement that the applying utility understands that, if any portion of the application is found to be false or to contain material misrepresentations, any authorities granted pursuant to the application may be revoked upon Commission order;
  - (VII) in lieu of the separate statements required by subparagraphs (b)(IV) through (VI) of this rule, a utility may include a statement that it has read, and agrees to abide by, the provisions of subparagraphs (b)(IV) through (VI) of this rule-;



- (VIII) a statement describing the applying utility's existing operations and general service area in Colorado.
  - (IX) for applications listed in subparagraphs (a)(I), (II), (III), (V), and (VI) of this rule, the applying utility's or parent company's and consolidated subsidiaries' most recent audited balance sheet, income statement, statement of retained earnings, and statement of cash flows so long as they provide Colorado specific financial information;
  - (X) a statement indicating the town or city, and any alternative town or city, in which the applying utility prefers any hearing be held; and
  - (XI) acknowledgment that, by signing the application, the applying utility understands that:
    - (A) the filing of the application does not by itself constitute approval of the application;
    - (B) if the application is granted, the applying utility shall not commence the requested action until the applying utility complies with applicable Commission rules and with any conditions established by Commission order granting the application; and
    - (C) if a hearing is held, the applying utility shall present evidence at the hearing to establish its qualifications to undertake, and its right to undertake, the requested action.
    - (D) in lieu of the statements contained in subparagraphs (b)(XI)(A) through (C) of this rule, an applying utility may include a statement that it has read, and agrees to abide by, the provisions of subparagraphs (b)(XI)(A) through (C) of this rule.
  - (XII) An attestation which is made under penalty of perjury; which is signed by an officer, a partner, an owner, an employee of, an agent for, or an attorney for the applying utility, as appropriate, who is authorized to act on behalf of the applying utility; and which states that the contents of the application are true, accurate, and correct. The application shall contain the title and the complete address of the affiant.
- (c) In addition to the requirements of specific rules, all applications shall include the information listed in subparagraphs (a)(I) through (V) of rule 1310. Applying utilities may either include the information in the application itself, or incorporate the information by reference to the most recent miscellaneous proceeding created under rule 1310.

- (d) Customer notice. Except as required or permitted by § 40-3-104, C.R.S., if the applicant is required by statute, Commission rule, or order to provide notice to its customers of the application, the applicant shall, within seven days after filing an application with the Commission, cause to have published notice of the filing of the application in each newspaper of general circulation in the municipalities impacted by the application. The applicant shall provide proof of such customer notice within 14 days of the publication in the newspaper. Failure to provide such notice or failure to provide the Commission with proof of notice may cause the Commission to deem the application incomplete. The applicant may also be required by statute, Commission rule, or order to provide additional notice to its customers of the application by first-class mailing or by hand-delivery. Both the newspaper notice and any additional customer notice(s) shall include the following:
- (I) the title “Notice of Application by [Name of the Utility] to [Purpose of Application]”;
  - (II) state that [Name of Utility] has applied to the Colorado Public Utilities Commission for approval to [Purpose of Application]. If the utility commonly uses another name when conducting business with its customers, the “also known as” name should also be identified in the notice to customers;
  - (III) provide a brief description of the proposal and the scope of the proposal, including an explanation of the possible impact upon persons receiving the notice;
  - (IV) identify which customer class(es) will be affected and the monthly customer rate impact by customer class, if customers’ rates are affected by the application;
  - (V) identify the proposed effective date of the application;
  - (VI) identify that the application was filed on less than statutory notice or if the applicant requests an expedited Commission decision, as applicable;
  - (VII) state that the filing is available for inspection in each local office of the applicant and at the Colorado Public Utilities Commission;
  - (VIII) identify the proceeding number, if known at the time the customer notice is provided;
  - (IX) state that any person may file written comment(s) or objection(s) concerning the application with the Commission. As part of this statement, the notice shall identify both the address and e-mail address of the Commission and shall state that the Commission will consider all written comments and objections submitted prior to the evidentiary hearing on the application;
  - (X) state that if a person desires to participate as a party in any proceeding before the Commission regarding the filing, such person shall file an intervention in accordance with the rule 1401 of the Commission’s Rules of Practice and Procedure or any applicable Commission order;

- (XI) state that the Commission may hold a public hearing in addition to an evidentiary hearing on the application and that if such a hearing is held members of the public may attend and make statements even if they did not file comments, objections or an intervention. State that if the application is uncontested or unopposed, the Commission may determine the matter without a hearing and without further notice; and
- (XII) state that any person desiring information regarding if and when hearings may be held shall submit a written request to the Commission or, alternatively, shall contact the External Affairs section of the Commission at its local or toll-free phone number. Such statement shall also identify both the local and toll-free phone numbers of the Commission's External Affairs section.

**4003. [Reserved].**

**4004. Disputes and Informal Complaints.**

- (a) For purposes of this rule, "dispute" means a concern, difficulty, or problem which needs resolution and which a customer or a person applying for service brings directly to the attention of the utility without the involvement of the Commission or Commission staff.
- (b) A dispute may be initiated orally or in writing. Using the procedures found in rule 1301, a utility shall conduct a full and prompt investigation of all disputes concerning utility service.
- (c) In accordance with the procedures in rule 1301, a utility shall conduct a full and prompt investigation of all informal complaints concerning utility service.
- (d) A utility shall comply with all rules regarding the timelines for responding to informal complaints.
- (e) If a current customer, or an applicant for service that is not a current customer, is dissatisfied with the utility's proposed adjustment or disposition of a dispute, the utility shall inform the person, customer or applicant for service of the right to make an informal complaint to the External Affairs section of the Commission and shall provide to the person, customer or applicant for service the address and toll free number of the Commission's External Affairs section.
- (f) A utility shall keep a record of each informal complaint and of each dispute. The record shall show the name and address of the initiating customer or person applying for service, the date and character of the issue, and the adjustment or disposition made. This record shall be open at all times to inspection by the person who initiated the informal complaint or dispute, by the Commission, and by Commission staff.

**4005. Records.**

- (a) Except as a specific rule may require, every utility shall maintain, for a period of not less than three years, and shall make available for inspection at its principal place of business during regular business hours, the following:
  - (I) records concerning disputes, which records are created pursuant to rule 4004;

- (II) complete records of tests to determine the heating value of gas, which records are created pursuant to rule 4202;
  - (III) records concerning interruptions and curtailments of service, which records are created pursuant to rule 4203;
  - (IV) transportation request logs, which records are created pursuant to paragraph 4205(e);
  - (V) notices of rejected transportation requests, which records are created pursuant to paragraph 4206(c);(VI) transportation agreements created pursuant to rule 4206;
  - (VII) all distribution pressure records, and all records or charts made with respect to rule 4208, appropriately annotated;
  - (VIII) meter calibration records created pursuant to under rule 4303;
  - (IX) records concerning meters, which records are created pursuant to rules 4305 and 4306;
  - (X) customer billing records, which records are created pursuant to paragraph 4401(a);
  - (XI) customer deposit records, which records are created pursuant to rule 4403;
  - (XII) records and supporting documentation concerning its cost assignment and allocation manual and fully-distributed cost study pursuant to paragraphs 4503(g) and 4504(e), for so long as the manual and study are in effect or are the subject of a complaint or a proceeding before the Commission;
  - (XIII) the total gas transported under each transportation service in Mcf or MMBtu and the associated total revenue;
  - (XIV) records concerning demand side management, pursuant to rules 4750 through 4760; and
  - (XV) as applicable, the records and documents required to be created pursuant to rules 4910 through 4920.
- (b) A utility shall maintain at each of its local offices and at its principal place of business all tariffs filed with the Commission and applying to Colorado rate areas. If the utility maintains a website, it shall also maintain its current and complete tariffs on its website.
- (c) A utility shall maintain its books of account and records in accordance with the provisions of 18 C.F.R. Part 201, the Uniform System of Accounts. A utility shall maintain its books of accounts and records separately and apart from those of its affiliates.
- (d) A utility shall preserve its records in accordance with the provisions of 18 C.F.R. Part 225, the Preservation of Records of Public Utilities and Licensees.

**4006. Reports.**

- (a) On or before April 30th of each year, a utility shall file with the Commission an annual report for the preceding calendar year. The utility shall submit the annual report on forms prescribed by the Commission; shall properly complete the forms; shall ensure the forms are verified and signed by a person authorized to act on behalf of the utility; and shall file in accordance with subparagraph 1204(a)(III) of the Commission's Rules of Practice and Procedure. If the Commission grants the utility an extension of time to file the annual report, the utility nevertheless shall file with the Commission, on or before April 30, the utility's total gross operating revenue from intrastate utility business transacted in Colorado for the preceding calendar year.
- (b) If a certified public accountant prepares an annual report for a utility, the utility shall file, within 30 days after the report is final, either two paper copies of the report with the Commission or an electronic copy through the Commission's E-Filing System.
- (c) On an annual basis, a utility shall file a report stating the average time taken for service personnel to respond to gas odor calls from customers for the following:
  - (I) the entire area served by the utility within Colorado; and
  - (II) each division of the utility assigned to serve a region or portion of the utility's entire service area.

**4007. [Reserved]**

**4008. Incorporation by Reference.**

- (a) The Commission incorporates by reference 18 C.F.R. Part 201 (as published on April 1, 2012) regarding the Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act. No later amendments to or editions of 18 C.F.R. Part 201 are incorporated into these rules.
- (b) The Commission incorporates by reference 18 C.F.R. Part 225 (as published on April 1, 2012) regarding the Preservation of Records of Natural Gas Companies. No later amendments to or editions of 18 C.F.R. Part 225 are incorporated into these rules.
- (c) Any material incorporated by reference in this Part 4 may be examined at the offices of the Commission, 1560 Broadway, Suite 250, Denver, Colorado 80202, during normal business hours, Monday through Friday, except when such days are state holidays. . Incorporated standards shall be available electronically and provided in certified copies, at cost, upon request. Restrictions on the provision of physical copies due to copyright protections may apply. The Director or the Director's designee will provide information regarding how the incorporated standards may be examined at any state public depository library. The standards and regulations are also available from the agency, organization or association originally issuing the code, standard, guideline or rule as follows: Code of Federal Regulations: [www.govinfo.gov/help/cfr](http://www.govinfo.gov/help/cfr).

## **CIVIL PENALTIES**

### **4009. Definitions.**

The following definitions apply to rules 4009, 4010, and 4976, unless a specific statute or rule provides otherwise. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- (a) “Civil penalty” means any monetary penalty levied against a public utility because of intentional violations of statutes in Articles 1 to 7 and 15 of Title 40, C.R.S., Commission rules, or Commission orders.
- (b) “Civil penalty assessment” means the act by the Commission of imposing a civil penalty against a public utility after the public utility has admitted liability or has been adjudicated by the Commission to be liable for intentional violations of statutes in Articles 1 to 7 and 15 of Title 40, C.R.S., Commission rules, or Commission orders.
- (c) “Civil penalty assessment notice” means the written document by which a public utility is given notice of an alleged intentional violation of statutes in Articles 1 to 7 and 15 of Title 40, C.R.S., Commission rules, or Commission orders and of a proposed civil penalty.
- (d) “Intentional violation.” A person acts “intentionally” or “with intent” when his conscious objective is to cause the specific result proscribed by the statute, rule, or order defining the violation.

### **4010. Regulated Gas Utility Violations, Civil Enforcement, and Enhancement of Civil Penalties.**

- (a) The Commission may impose a civil penalty in accordance with the requirements and procedures contained in § 40-7-113.5, C.R.S., § 40-7-116.5, C.R.S., and paragraph 1302(b), 4 Code of Colorado Regulations 723-1, for intentional violations of statutes in Articles 1 to 7 and 15 of Title 40, C.R.S., Commission rules, or Commission orders as specified in §§ 40-7-113.5 and 40-7-116.5, C.R.S., and in these rules.
- (b) The Director of the Commission or his or her designee shall have the authority to issue civil penalty assessments for the violations enumerated in § 40-7-113.5, C.R.S., subject to hearing before the Commission. When a public utility is cited for an alleged intentional violation, the public utility shall be given notice of the alleged violation in the form of a civil penalty assessment notice.
- (c) The public utility cited for an alleged intentional violation may either admit liability for the violation pursuant to § 40-7-116.5(1)(c) or the public utility may contest the alleged violation pursuant to § 40-7-116.5(1)(d), C.R.S. At any hearing contesting an alleged violation, trial staff shall have the burden of demonstrating a violation by a preponderance of the evidence.
- (d) In any written decision entered by the Commission pursuant to § 40-6-109, C.R.S., adjudicating a public utility liable for an intentional violation of a statute in Articles 1 to 7 and 15 of Title 40, C.R.S., a Commission rule, or a Commission order, the Commission may impose a civil penalty of not more than two thousand dollars, pursuant to § 40-7-113.5(1), C.R.S. In imposing any civil penalty pursuant to § 40-7-113.5(1), C.R.S., the Commission shall consider the factors set forth in Rule 1302(b).

- (e) The Commission may assess doubled or tripled civil penalties against any public utility, as provided by § 40-7-113.5(3), C.R.S., § 40-7-113.5(4), C.R.S., and this rule.
- (f) The Commission may assess any public utility a civil penalty containing doubled penalties only if:
  - (I) the public utility has admitted liability by paying the civil penalty assessment for, or has been adjudicated by the Commission in an administratively final written decision to be liable for, engaging in prior conduct that constituted an intentional violation of a statute in Articles 1 to 7 and 15 of Title 40, C.R.S., a Commission rule, or a Commission order;
  - (II) the conduct for which doubled civil penalties are sought violates the same statute, rule, or order as conduct for which the public utility has admitted liability by paying the civil penalty assessment, or conduct for which the public utility has been adjudicated by the Commission in an administratively final written decision to be liable; and
  - (III) the conduct for which doubled civil penalties are sought occurred within one year after conduct for which the public utility has admitted liability by paying the civil penalty assessment, or conduct for which the public utility has been adjudicated by the Commission in an administratively final written decision to be liable
- (g) The Commission may assess any public utility a civil penalty containing tripled penalties only if:
  - (I) the public utility has admitted liability by paying the civil penalty assessment for, or has been adjudicated by the Commission in an administratively final written decision to be liable for, engaging in prior conduct that constituted two or more prior intentional violations of a statute in Articles 1 to 7 and 15 of Title 40, C.R.S., a Commission rule, or a Commission order;
  - (II) the conduct for which tripled civil penalties are sought violates the same statute, rule, or order as conduct for which the public utility has either admitted liability by paying the civil penalty assessment or been adjudicated by the Commission in an administratively final written decision to be liable, in at least two prior instances; and
  - (III) the conduct for which tripled civil penalties are sought occurred within one year after the two most recent prior instances of conduct for which the public utility has either admitted liability by paying the civil penalty assessment, or been adjudicated by the Commission in an administratively final written decision to be liable.
- (h) When more than two instances of prior conduct exist, the Commission shall only consider those instances occurring within one year prior to the date of such alleged conduct for which tripled civil penalties are sought.
- (i) Nothing in this rule shall preclude the assessment of tripled penalties when doubled and tripled penalties are sought in the same civil penalty assessment notice.
- (j) The Commission shall not issue a decision on doubled or tripled penalties until after the effective date of the administratively final Commission decision upon which the single civil penalty was based.

- (k) The civil penalty assessment notice shall contain the maximum penalty amount provided by rule for each individual violation noted, with a separate provision for a reduced penalty of 50 percent of the penalty amount sought if paid within ten days of the public utility's receipt of the civil penalty assessment notice.
- (l) The civil penalty assessment notice shall contain the maximum amount of the penalty surcharge pursuant to § 24-34-108(2), C.R.S., if any.
- (m) A penalty surcharge referred to in paragraph (l) of this rule shall be equal to the percentage set by the Department of Regulatory Agencies on an annual basis. The surcharge shall not be included in the calculation of the statutory limits set in § 40-7-113.5(5), C.R.S.
- (n) Nothing in these rules shall affect the Commission's ability to pursue other remedies in lieu of issuing civil penalties.

**4011. – 4024. [Reserved].**

## **CUSTOMER DATA ACCESS AND PRIVACY**

### **4025. Scope and Applicability.**

- (a) The basis and purpose of these rules is to describe the protection of and limited access to customer data for gas utilities over which the Commission has jurisdiction. These rules are applicable to all utilities except for certain provisions as defined in the rule.
- (b) For the purpose of the Customer Data Access and Privacy Rules, gas utilities are classed into three tiers: a Tier I utility serves more than 150,000 gas customers; a Tier II utility serves between 50,000 and 150,000 gas customers. A Tier III utility serves fewer than 50,000 gas customers.
- (c) No Tier III utility is required to:
  - (I) include in its tariffs a description of standard and non-standard customer data that the utility is able to provide to the customer or to any third party recipient (see paragraph 4027(c));
  - (II) provide customer notice each year regarding customer data (see rule 4028);
  - (III) make customer consent forms for the disclosure of customer data available to customers or third parties (see rule 4029);
  - (IV) disclose aggregated data (see rule 4033); or
  - (V) provide a community energy report (see rule 4035).



However, a Tier III utility may include a description of standard and non-standard customer data that the utility is able to provide to the customer or to any third-party recipient in its tariffs (in accordance with paragraph 4027(c)). Commencing upon the effective date of such description, the Tier III utility shall be deemed to be a Tier II utility for purposes of these Customer Data Access and Privacy Rules for so long as such tariff provisions remain in effect.

**4026. Customer Data.**

- (a) A utility shall maintain standard customer data sufficient to allow a customer to understand his or her energy usage at a level of detail commensurate with the metering technology used to serve the customer.

**4027. Privacy, Access, and Disclosure.**

- (a) A utility shall protect customer data in the utility's possession or control to maintain the privacy of customers, while providing reasonable access to that data. A utility is only authorized to use customer data to provide regulated utility service in the ordinary course of business.
- (b) A utility shall not disclose customer data unless such disclosure conforms to these rules, except as required by law or to comply with Commission rule. Illustratively, this includes responses to requests of the Commission, warrants, subpoenas, court orders, or as authorized by § 16-15.5-102, C.R.S.
- (c) A utility shall include in its tariffs a description of customer data that the utility is able to provide to the customer or to any third party recipient to whom the customer has authorized disclosure of the customer's data within the utility's technological and data capabilities. At a minimum, the utility's tariff must provide the following:
  - (I) a description of standard customer data and non-standard customer data and the frequency of customer data updates that will be available (annual, monthly, daily, etc.);
  - (II) the method and frequency of customer data transmittal and access available (electronic, paper, etc.) as well as the security protections or requirements for such transmittal;
  - (III) a timeframe for processing requests;
  - (IV) any rate associated with processing a request for non-standard customer data; and
  - (V) any charges associated with obtaining non-standard customer data.
- (d) As part of basic utility service, a utility shall provide access to the customer's standard customer data in electronic machine-readable form, without additional charge, to the customer or to any third party recipient to whom the customer has authorized disclosure of the customer's customer data. Such access shall conform to nationally recognized open standards and best practices. The utility shall provide access in a manner that ensures adequate protections for the utility's system security and the continued privacy of the customer data during transmission.
- (e) Nothing in these rules shall limit a customer's right to provide his or her customer data to anyone.

- (f) A utility and each of its directors, officers and employees that discloses customer data pursuant to a customer's authorization in accordance with these data privacy rules shall not be liable or responsible for any claims for loss or damages resulting from the utility's disclosure of customer data.

**4028. Customer Notice.**

- (a) A utility shall provide each year to its customers a written notice complying with this rule. The utility shall conspicuously post on its website notice of its privacy and security policies governing access to and disclosure of customer data and aggregated data to third-parties. This notice shall:
- (I) explain what is available to customers, as standard and/or non-standard customer data (e.g., daily versus hourly data);
  - (II) describe the frequency that the utility can provide customer data based on a request for standard data (e.g., on a weekly or monthly basis);
  - (III) advise customers that their customer data may provide insight into their activities within the premises receiving service;
  - (IV) inform customers that the privacy and security of their customer data will be protected by the utility while in its possession;
  - (V) explain that customers can access their standard customer data, as identified by the utility's tariff, without additional charge;
  - (VI) advise customers that their customer data will not be disclosed to third parties, except:
    - (A) as necessary to provide regulated utility services to the customers;
    - (B) as otherwise permitted or required by law or Commission rule; or
    - (C) pursuant to the authorization given by the customer in accordance with these rules.
  - (VII) describe the utility's policies regarding how a customer can authorize access and disclosure of their customer data to third-parties. With regard to such third party data disclosure, the notice shall:
    - (A) inform customers that declining a request for disclosure of customer data to a third party will not affect the provision of utility service that the customer receives from the utility; and
    - (B) explain that any customer consent for access to, disclosure of, or use of a customer's customer data by a third party may be terminated or limited by the customer of record at any time and inform the customers of the process for doing so.

- (VIII) explain that aggregated data does not contain customer identifying information and inform customers that customer data may be used to create aggregated data that will not contain customer identifying information;
- (IX) explain that the utility may provide aggregated data to third-parties, subject to its obligation under paragraph 4033(a);
- (X) be viewable on-line and printed in ten point or larger font;
- (XI) be sent either separately or included as an insert in a regular monthly bill, or, for those customers who have consented to receive e-bills, such notice may be sent electronically separately from an e-bill, conspicuously marked and stating clearly that important information on the utility's privacy practices is contained therein;
- (XII) be available in English and Spanish. The customer notice may also be translated to a language other than English or Spanish by a third party or the utility. Forms translated to other languages in accordance with this rule must be accepted by utilities, and may be relied upon, after the English version of the form, the translated version of the form, and an affidavit attesting to the accurate and complete translation from the English version of the form, have been provided to the Commission and the utility possessing the data. Such affidavit must be executed by an interpreter on the active roster of interpreters maintained by the Office of Language Access of the Colorado Judicial Branch. If the utility incurs a cost for translation made at the request of a third party, it may charge the requestor for such cost and may include a reasonable administrative fee in addition to the translation cost; and
- (XIII) provide a customer service phone number and web address where customers can direct additional questions or obtain additional information regarding their customer data, the disclosure of customer data or aggregated data, or the utility's privacy policies and procedures with respect to customer data or aggregated data.

**4029. Customer Consent Form for the Disclosure of their Customer Data to Third Party Recipients by a Utility.**

- (a) A utility shall make available to any third party a consent form for the disclosure of customer data that is maintained by the Commission and available from the Commission's website. The form shall be available electronically from the utility. The consent form shall be provided in a non-electronic format by a utility upon request from a customer or third party.
- (b) In addition to the Commission supplied form, a utility may create and make available a consent form that:
  - (I) includes the same information contained in the annual notice provided under subparagraphs 4028(a)(V), (VI), (VII), and (XIII);
  - (II) provides spaces for the following required information regarding the third party recipient of the customer data:

- (A) the name, including trade name if applicable, physical address, mailing address, e-mail address, and telephone number;
  - (B) the uses of the data for which the customer is allowing disclosure;
  - (C) the time period (e.g., months, years) for which data are being requested; and
  - (D) the description of the data that are being requested;
- (III) states that the consent is valid until terminated;
- (IV) states that the customer must notify the utility service provider in writing (electronically or non-electronically) to terminate the consent including appropriate utility contact information;
- (V) states any additional terms except an inducement for the customer's disclosure;
- (VI) be viewable on-line and printed in ten point or larger font; and
- (VII) provides notice to the customer that the utility shall not be responsible for monitoring or taking any steps to ensure that the third party to whom the data is disclosed is maintaining the confidentiality of the data or using the data as intended by the customer.
- (c) A utility may make available an electronic customer consent process for disclosure of customer data to a third party (e.g., a utility controlled web portal) that authenticates the customer identity. The contents of the electronic consent process must generally follow the format of the model consent to disclose customer data form, be clear, and include the elements to be provided pursuant to paragraph (a) of this rule. No utility is required to provide an electronic consent process in a language other than English.
- (d) A utility may make available an in-person consent process for disclosure of customer data.
- (e) A consent form may be submitted to the utility through electronic or non-electronic methods.
- (f) The scope of consent given shall be defined by the terms of the consent form, except that changes of contact names for an organization, trade name, or utility over time do not invalidate consent as to the respective organization, trade name, or utility. Because the contact named for an organization, trade name, or utility is a representative of the respective organization, trade name, or utility, consent terminates as to such contact when the relationship with the organization, trade name, or utility terminates. Modifications to the consent form over time do not invalidate previous consent. Consent need not be provided on a new form so long as the data provided remains within the scope of consent.
- (g) Customer consent forms shall be available in English and Spanish. Customer consent forms may be translated to into languages other than English or Spanish by a third party or the utility. Forms translated to other languages in accordance with this rule must be accepted by utilities, and may be relied upon, after the English version of the form, the translated version of the form, and an affidavit attesting to the accurate and complete translation from the English version of the form, have been provided to the Commission and the utility possessing the data. Such affidavit must

be signed by an interpreter on the active roster of interpreters maintained by the Office of Language Access of the Colorado Judicial Branch. If a utility incurs a cost for a translation at the request of a third party, it may charge the requestor for such cost and may include a reasonable administrative fee in addition to the translation cost.

- (h) Any customer consent forms available from the Commission's website shall be presumed to comply with these rules.

**4030. Access to Customer Data for the Provision of Regulated Utility Service.**

- (a) A utility may disclose customer data to a contracted agent provided that the contract requires the agent to:
  - (I) implement and maintain data security procedures and practices to protect the customer data from unauthorized access, destruction, use, modification, or disclosure that are equal to or greater than the data privacy and security policies and procedures used by the utility internally to protect customer data;
  - (II) use customer data solely for the purpose of the contract and prohibits the use of customer data for a secondary commercial purpose not related to the purpose of the contract without first obtaining the customer's consent as provided for in these rules;
  - (III) return to the utility or destroy any customer data that is no longer necessary for the purpose for which it was transferred; and
  - (IV) execute a non-disclosure agreement with the utility.
- (b) The utility shall maintain records of the disclosure of customer data to contracted agents for a minimum of three years. Such records shall include all contracts with the contracted agent and executed non-disclosure agreements.

**4031. Local Government Access to Customer Data from a Utility for Audit.**

- (a) A utility may disclose customer data to a local government either with an audit required to be provided pursuant to a final Commission decision (e.g., a decision approving a franchise agreement) or as reasonably necessary for an audit conducted by a governmental entity of franchise fees paid to them by the utility, provided that:
  - (I) disclosure is not otherwise prohibited by a final Commission decision (e.g., Commission-approved franchise between the utility and the local government);
  - (II) disclosure is made to a designated auditor or auditor's office, who is either an employee or agent of the local government;
  - (III) the auditor collects and uses the customer data solely for the purpose of reviewing or conducting the audit and is prohibited from disclosing or using the customer data for a purpose not related to the audit;

- (IV) the local government implements and maintains data security procedures and practices to protect the customer data from unauthorized access, destruction, use, or modification;
  - (V) the local government destroys or returns to the utility of any customer data no longer necessary for the purpose for which it was transferred unless state law or the municipality's state-mandated retention schedule requires otherwise;
  - (VI) the local government agrees not to permit access to the data by anyone that has not agreed to abide by the terms pursuant to which the data was provided by the utility. This includes, but is not limited to, all interns, subcontractors, staff, other workforce members, and consultants;
  - (VII) the local government agrees that any recipient of the data pursuant to this rule does not obtain any right, title or interest in any of the data provided by the utility;
  - (VIII) governing law or a non-disclosure agreement executed with the utility requires that the local government, at a minimum, comply with the requirements of this rule; and
  - (IX) the data requested is for utility customers served in the boundaries of the local government.
- (b) The utility shall maintain records of all disclosures of customer data to local government requestors for a minimum of three years.
  - (c) Availability of customer data pursuant to this rule does not preclude a local government from requesting other data reports.

**4032. Third Party Access to Customer Data from a Utility.**

- (a) Except as provided in this rule, paragraph 4027(b), rule 4030, and rule 4031, a utility shall not disclose customer data to any third party unless the customer or a third party acting on behalf of a customer submits a paper or electronic signed consent to disclose customer data form that has been executed by the customer of record.
- (b) Incomplete or non-compliant consent to disclose customer data forms are not valid and shall be rejected by the utility.
- (c) The utility shall maintain records of all of the disclosures of customer data to third party requestors. Such records shall include a copy of the customer's signed consent to disclose customer data form, all identifying documentation produced by the third party requestor, the customer's agreed upon terms of use, the date(s) and frequency of disclosure, and a description of the customer data disclosed.
- (d) The utility shall maintain records of customer data disclosures for a minimum of three years and shall make the records of the disclosure of a customer's customer data available for review by the customer within five business days of receiving a paper or electronic request from the customer, or at such greater time as is mutually agreed between the utility and the customer.

**4033. Requests for Aggregated Data Reports from a Utility.**

- (a) A utility shall not disclose aggregated data unless the recipient is authorized to receive all customer data within the aggregated data, and the disclosure otherwise conforms to this rule and rules 4031, 4034, and 4035. In aggregating customer data to create an aggregated data report, a utility must ensure that the data do not include any personal information or a unique identifier.
- (b) At a minimum, a particular aggregation must contain at least fifteen customers; and, within any customer class no single customer's customer data or premise associated with a single customer's customer data may comprise 15 percent or more of the total customer data aggregated per customer class to generate the aggregated data report (the "15/15 Rule").
- (c) If an aggregated data report cannot be generated in compliance with paragraph 4033(b), the utility shall notify the requestor that the aggregated data, as requested, cannot be disclosed and identify the reason(s) the request was denied. The requestor shall be given an opportunity to revise its aggregated data request in order to address the identified reason(s). An aggregated data request may be revised by expanding the number of customers or premise accounts in the request, expanding the geographic area included in the request, combining different customer classes or rate categories, or other applicable means of aggregating.
- (d) A utility shall include in its tariffs a description of standard and non-standard aggregated data reports available from the utility to any requestor. At a minimum, the utility's tariff shall provide the following:
  - (I) a description of standard and non-standard aggregated data reports available from the utility including all available selection parameters (customer data or other data);
  - (II) the frequency of data collection (annual, monthly, daily, etc.);
  - (III) the method of transmittal available (electronic, paper, etc.) and the security protections or requirements for such transmittal;
  - (IV) the charge for providing a standard aggregated data report or the hourly charge for compiling a non-standard aggregated data report;
  - (V) the timeframe for processing requests; and
  - (VI) a request form for submitting a data request for aggregated data reports to the utility identifying any information necessary from the requestor in order for the utility to process the request.
- (e) If a utility is unable to fulfill a non-standard aggregated data report request because it does not have and/or does not elect to or cannot obtain all of the data the requestor wishes to include in the aggregated data report, then the utility may contract with a contracted agent to include the additional data and process it along with the customer data in the utility's possession, to generate a non-standard aggregated data report.

- (f) A utility and each of its directors, officers and employees that discloses aggregated data as provided in these data privacy rules shall not be liable or responsible for any claims for loss or damages resulting from the utility's disclosure of aggregated data.
- (g) A utility shall not provide aggregated customer data in response to multiple overlapping requests from or on behalf of the same requestor that have the potential to identify customer data.

**4034. Property Owner Request for Whole Building Energy Use Data from a Utility.**

- (a) If requested by a property owner or its authorized agent, a Tier I utility shall provide whole building energy use data to the property owner or its authorized agent so long as:
  - (I) the whole building energy use data contains at least four customers or tenants, which may include the property owner's own account; and no single customer's customer data, unless it is the property owner's, comprises more than 50 percent of the whole building energy use data used to generate the whole building energy use data report;
  - (II) the property owner or its authorized agent agrees to not disclose the whole building energy use data except for the purposes of building benchmarking, identifying energy efficiency projects, and energy management; and
  - (III) the property owner or its authorized agent signs a non-disclosure agreement with the utility requiring the property owner, at a minimum to:
    - (A) take appropriate administrative, technical, and physical safeguards to protect the whole building data from any unauthorized use or disclosure to protect the data from unauthorized access, destruction, use, modification, or disclosure;
    - (B) only use the whole building data only for the purposes of building benchmarking, identifying energy efficiency projects, energy management, and complying with laws or ordinances;
    - (C) agree not to attempt to determine an individual utility customer's energy use from the whole building data and not to use the information to contact the subject of the information;
    - (D) agree not to use the whole building energy use data for a secondary commercial purpose not related to the authorized purpose without first obtaining the customer's consent as provided for in these rules;
    - (E) destroy any whole building energy use data that is no longer necessary for the purpose for which it was transferred;
    - (F) agree not to permit access to the whole building data by anyone that has not agreed to abide by the terms pursuant to which the data was provided by the utility. This includes, but is not limited to, all interns, subcontractors, staff, other workforce members, and consultants; and



- (G) agree that any recipient of the whole building data pursuant to this rule does not obtain any right, title or interest in any of the data provided by the utility.
- (b) Upon request by a property owner or its authorized agent, a Tier II utility shall provide whole building energy use data upon the same conditions to the extent of, and based upon, information available in the ordinary course of business.
- (c) A utility shall provide a requested whole building energy use data report in electronic, machine readable format that conforms to nationally recognized open standards and best practices.
- (d) A utility may charge a property owner or its authorized agent for the development of a whole building energy use data report. Such rate shall be determined in a utility tariff as a non-standard aggregated data report. Alternatively, the utility need not charge the customer if the cost to charge a property owner or its authorized agent is greater than the cost to develop a whole building energy use data report.
- (e) Availability of whole building energy use data pursuant to this rule does not preclude a property owner from requesting other data reports.

**4035. Community Energy Reports.**

- (a) A Tier I utility shall generate a community energy report for each local government other than a Colorado county included in its service territory with 50,000 or more residents. A Tier I utility shall generate a community energy report for each Colorado county included in its service territory with 100,000 or more residents. Any local government with fewer than 50,000 residents and Colorado county with fewer than 100,000 residents or a minority of whom are served by a Tier I utility shall be treated as if it had 50,000 or more residents served by the Tier I upon request from the local government or county. Such requests shall be made by January 31 of the calendar year following the reporting year and shall continue in effect until such time as the request is withdrawn or cancelled by the local government. All population thresholds shall be based on the most recent population estimate from the Colorado State Demography Office and where the utility serves the majority of the population.
- (b) On or before June 1 of every year, a Tier I utility shall make publicly available for download all community energy reports generated for the prior year. Reports shall be available in an electronic machine-readable form that conforms to nationally recognized open standards and best practices.
- (c) The community energy report shall include the following information and aggregated data for the utility and its customers and specific to the local government for the prior calendar year:
  - (I) the annual dekatherms consumed by customers, provided by residential, commercial, and industrial classes;
  - (II) the average number of customers in the residential, commercial, and industrial class; and
  - (III) the total annual energy saved (in dekatherms) from energy efficiency measures installed.

- (d) A local government may submit, or have another local government submit on its behalf, a GIS data to define its jurisdictional boundaries prior to the issuance of the community energy report.
- (e) Upon request by a local government, a Tier II utility shall generate a community energy report, in accordance with this rule, consistent with the utility's meter, network, or data capabilities. Such requests shall be made by January 31 of the calendar year following the reporting year and shall continue in effect until such time as the request is withdrawn or cancelled by the local government. On or before June 1 of every year, the utility shall make publicly available for download all community energy reports generated for the prior year. Reports shall be available in an electronic machine-readable form that conforms to nationally recognized open standards and best practices.
- (f) Availability of the community energy report pursuant to this rule does not preclude a local government from requesting other data reports.

**4036.– 4099. [Reserved].**

## **OPERATING AUTHORITY**

### **4100. Certificate of Public Convenience and Necessity for a Franchise.**

- (a) A utility seeking authority to provide service pursuant to a franchise shall file an application pursuant to this rule. When a utility enters into a franchise agreement with a municipality for the first time, it shall obtain authority from the Commission pursuant to § 40-5-102, C.R.S. prior to providing service under that initial franchise agreement. A utility maintains the right and obligation to serve a municipality within its service territory after the expiration of any franchise agreement.
- (b) An application for certificate of public convenience and necessity to exercise franchise rights shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) the information required in paragraphs 4002(b) and 4002(c);
  - (II) a statement of the facts (not conclusory statements) relied upon by the applying utility to show that the public convenience and necessity require the granting of the application;
  - (III) a statement describing the franchise rights proposed to be exercised. The statement shall include a description of the type of utility service to be rendered and a description of the city or town sought to be served;
  - (IV) a certified copy of the franchise ordinance; proof of publication, adoption, and acceptance by the applying utility; a statement as to the number of customers served or to be served and the population of the city or town; and any other pertinent information;
  - (V) a statement describing in detail the extent to which the applying utility is an affiliate of any other utility which holds authority duplicating in any respect the authority sought;

- (VI) the feasibility study for areas previously not served by the applying utility, which study shall at least include estimated investment, income, and expense. An applying utility may request that its most recent audited balance sheet, income statement, statement of retained earnings, and statement of cash flows be submitted in lieu of a feasibility study; and
- (VII) a statement of the names of public utilities and other entities of like character providing similar service in or near the area sought to be served.

**4101. Certificate of Public Convenience and Necessity for Service Territory.**

- (a) A utility seeking authority to provide service in a new service territory shall file an application pursuant to this rule. A utility cannot provide service to a new geographic area without authority from the Commission, unless the utility extends its facilities and service:
  - (I) within a city and county or city or town within which the utility has lawfully commenced operations;
  - (II) into territory contiguous to the utility's facility, line, plant, or system that is not served by a public utility providing the same commodity or service; or
  - (III) within or to territory already served by the utility and the extension is necessary in the ordinary course of business.
- (b) An application for certificate of public convenience and necessity to provide service in a new territory shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) the information required in paragraphs 4002(b) and 4002(c);
  - (II) a statement of the facts (not conclusory statements) relied upon by the applying utility to show that the public convenience and necessity require the granting of the application;
  - (III) a description of the type of utility service to be rendered and a description of the area sought to be served;
  - (IV) a map showing the specific geographic area that the applying utility proposes to serve. If the applying utility intends to phase in service in the territory over time, specific areas and proposed in-service dates shall be included. The map shall describe the geographic areas in section, township, and range convention;
  - (V) a statement describing in detail the extent to which the applying utility is an affiliate of any other utility which holds authority duplicating in any respect the territory sought;
  - (VI) a statement of the names of public utilities and other entities of like character providing similar service in or near the area involved in the application;

- (VII) a feasibility study for the proposed area to be served, which shall at least include estimated investment, income, and expense. An applying utility may request that its most recent audited balance sheet, income statement, statement of retained earnings, and statement of cash flows be submitted in lieu of a feasibility study; and
- (VIII) a statement of the names of public utilities and other entities of like character providing similar service in or near the area sought to be served.

**4102. Certificate of Public Convenience and Necessity for Facilities.**

- (a) A utility seeking authority to construct and to operate a facility or an extension of a facility pursuant to § 40-5-101, C.R.S., shall file an application pursuant to this rule. The utility need not apply to the Commission for approval of construction and operation of a facility or an extension of a facility which is in the ordinary course of business. The utility shall apply to the Commission for approval of construction and operation of a facility or an extension of a facility which is not in the ordinary course of business.
- (b) An application for certificate of public convenience and necessity to construct and to operate facilities or an extension of a facility pursuant to § 40-5-101, C.R.S., shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) the information required in paragraphs 4002(b) and 4002(c);
  - (II) a statement of the facts (not conclusory statements) relied upon by the applying utility to show that the public convenience and necessity require the granting of the application or citation to any Commission decision that is relevant to the proposed facilities;
  - (III) a description of the proposed facilities to be constructed;
  - (IV) estimated cost of the proposed facilities to be constructed;
  - (V) anticipated construction start date, construction period, and in-service date;
  - (VI) a map showing the general area or actual locations where facilities will be constructed, population centers, major highways, and county and state boundaries; and
  - (VII) as applicable, information on alternatives studied, costs for those alternatives, and criteria used to rank or eliminate alternatives.

**4103. Certificate Amendments for Changes in Service, in Service Territory, or in Facilities.**

- (a) A utility seeking authority to do the following shall file an application pursuant to this rule: amend a certificate of public convenience and necessity in order to extend, to restrict, to curtail, or to abandon or to discontinue without equivalent replacement any service, service area, or facility. A utility shall not extend, restrict, curtail, or abandon or discontinue without equivalent replacement any service, service area, or facility not in the ordinary course of business without authority from the Commission.

- (b) An application to amend a certificate of public convenience and necessity in order to change, to extend, to restrict, to curtail, to abandon, or to discontinue any service, service area, or facility without equivalent replacement shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
- (I) all information required in paragraphs 4002(b) and 4002(c);
  - (II) if the application for amendment pertains to a certificate of public convenience and necessity for facilities, all of the information required in rule 4102;
  - (III) if the application for amendment pertains to a certificate of public convenience and necessity for franchise rights, all of the information required in rule 4100;
  - (IV) if the application for amendment pertains to a certificate of public convenience and necessity for service territory, all of the information required in rule 4101;
  - (V) if the application for amendment pertains to a service, the application shall include:
    - (A) the requested effective date for the extension, restriction, curtailment, or abandonment or discontinuance without equivalent replacement of the service; and
    - (B) a description of the extension, restriction, curtailment, or abandonment or discontinuance without equivalent replacement sought. This shall include maps, as applicable. This shall also include a description of the applying utility's existing operations and general service area.
- (c) Customer notice of application. In addition to complying with the notice requirements of the Commission's Rules Regulating Practice and Procedure, a utility applying to curtail, restrict, abandon or discontinue service without equivalent replacement shall prepare a written notice as provided in subparagraphs 4002(d)(I) through (XII) and shall mail or deliver the notice at least 30 days before the application's requested effective date to each of the applying utility's affected customers. The customer notice shall include a statement detailing the requested restriction, curtailment, or abandonment or discontinuance without equivalent replacement.
- (d) If no customers will be affected by the grant of the application, the notice must meet the requirements of subparagraphs 4002(d)(I) through (XII) and shall be mailed to the Board of County Commissioners of each affected county, and to the mayor of each affected city, town, or municipality.

**4104. Transfers, Controlling Interest, and Mergers.**

- (a) A utility seeking authority to do any of the following shall file an application pursuant to this rule: transfer a certificate of public convenience and necessity; transfer or obtain a controlling interest in a utility, whether the transfer of control is effected by the transfer of assets, by the transfer of stock, by merger or by other form of business combination; or transfer assets subject to the jurisdiction of the Commission outside the normal course of business. A utility cannot transfer a certificate of public convenience and necessity; transfer or obtain a controlling interest in any

utility; or transfer assets outside the normal course of business without authority from the Commission.

- (b) An application to transfer a certificate of public convenience and necessity, to transfer or obtain a controlling interest in a utility, or to transfer assets subject to the jurisdiction of the Commission shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
- (I) the information required in paragraphs 4002(b) and 4002(c), as pertinent to each party to the transaction;
  - (II) a statement showing accounting entries, under the Uniform System of Accounts, including any plant acquisition adjustment, gain, or loss proposed on the books by each party before and after the transaction which is the subject of the application;
  - (III) any agreement for merger, sales agreement, or contract of sale pertinent to the transaction which is the subject of the application;
  - (IV) all facts showing that the transaction which is the subject of the application is not contrary to the public interest;
  - (V) an evaluation of the benefits and detriments to the customers of each party and to all other persons who will be affected by the transaction which is the subject of the application; and.
  - (VI) a comparison of the kinds and costs of service rendered before and after the transaction which is the subject of the application.
- (c) An application to transfer a certificate of public convenience and necessity, an application to transfer assets subject to the jurisdiction of the Commission, or an application to transfer or obtain control of the utility may be made by joint or separate application of the transferor and the transferee.
- (d) When control of a utility is transferred to another entity, or the utility's name is changed, the utility which will afterwards operate under the certificate of public convenience and necessity shall file with the Commission a tariff adoption notice, shall post the tariff adoption notice in a prominent public place in each local office and principal place of business of the utility, and shall have the tariff adoption notice available for public inspection at each local office and principal place of business. Adoption notice forms are available from the Commission. The tariff adoption notice shall contain all of the following information:
- (I) the name, phone number, and complete address of the adopting utility;
  - (II) the name of the previous utility;
  - (III) the number of the tariff adopted and the description or title of the tariff adopted;
  - (IV) the number of the tariff after adoption and the description or title of the tariff after adoption; and

- (V) unless otherwise requested by the applying utility in its application, a statement that the adopting utility is adopting as its own all rates, rules, terms, conditions, agreements, concurrences, instruments, and all other provisions that have been filed or adopted by the previous utility.

**4105. Securities and Liens.**

- (a) Subject to the exception contained in paragraph (h) of this rule, a utility which either derives more than five percent of its consolidated gross revenues in Colorado as a public utility or derives a lesser percentage if its revenues are earned by supplying an amount of energy which equals five percent or more of Colorado's consumption shall file an application for Commission approval of any proposal to issue or to assume any security or to create a lien.
- (b) An application for the issuance or assumption of securities with a maturity of 12 months or more or to create a lien shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) all information required in paragraphs 4002(b) and 4002(c);
  - (II) the resolution of the applying utility's board of directors approving the issuance, or assumption of the securities or to create a lien, together with, as applicable and available, the proposed indenture requirements, the mortgage note, the amendment to the loan contract, and the contract for sale of securities or creation of a lien;
  - (III) a statement describing each short-term and long-term indebtedness outstanding on the date of the most recent balance sheet;
  - (IV) a statement describing the classes and amounts of capital stock authorized by the articles of incorporation and the amount by each class of capital stock outstanding on the date of the most recent balance sheet;
  - (V) a statement of capital structure showing common equity, long-term debt, preferred stock, if any, and pro forma capital structure on the date of the most recent balance sheet giving effect to the issuance of the proposed securities. Debt and equity percentages to total capitalization, actual and pro forma, shall be shown;
  - (VI) a statement of the amount and rate of dividends declared and paid, or the amount and year of capital credits assigned and capital credits refunded, during the previous four calendar years including the present year to the date of the most recent balance sheet;
  - (VII) a statement describing the type and amount of securities to be issued; the anticipated interest rate or dividend rate; the redemption or sinking fund provisions, if any; and, within ten days of their filing with the Securities and Exchange Commission, the registration statement, related forms, and preliminary prospectus filed with the Securities and Exchange Commission relating to the proposed issuance;
  - (VIII) a statement of proposed uses, including construction, to which the funds will be or have been applied and a concise statement of the need for the funds; and

- (IX) a statement of the estimated cost of financing.
- (c) For applications for the creation of a lien on the applying utility's property situated within the State of Colorado where the creation of the lien is not related to the issuance or assumption of a security, the application shall also include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
- (I) a description of the property which will be subject to the lien;
  - (II) the amount of the lien;
  - (III) the proposed use of the funds to be received from the lien;
  - (IV) the estimated cost for the creation of the lien;
  - (V) the anticipated duration of the lien;
  - (VI) the anticipated release date of the lien;
  - (VII) the retirement payment plan to release the lien;
  - (VIII) a description of how the applying utility will ensure that neither the creation of the lien nor the use of the proceeds will violate § 40-3-114, C.R.S.;
  - (IX) a statement that, for the duration of the lien, the applying utility will advise the Commission within ten days of any bankruptcy, foreclosure, or liquidation proceeding; and
  - (X) a statement that the applying utility will advise the Commission within ten days of any deviation from its lien retirement payment plan;
- (d) The Commission shall issue notice of the application, which shall set a ten-day intervention period and a hearing date.
- (e) Customer notice. Within three days after the filing of an application to issue or to assume a security, the applying utility shall publish notice of the filing of the application in a newspaper of general circulation. The notice shall include, in addition to the information required by subparagraphs 4002(d)(I) – (XII), the address of the applicant.
- (f) The applying utility shall file with the Commission the published notice and an affidavit of publication as soon as possible after the filing of the application. The Commission shall not grant the application without the notice and the affidavit of publication.
- (g) The Commission shall give priority to an application made pursuant to this rule and shall grant or deny the application within 30 days after filing, unless the Commission, for good cause shown, enters an order granting an extension and stating fully the facts necessitating the extension. The Commission shall approve or disapprove an application made pursuant to this rule by written order.



- (h) Pursuant to § 40-1-104, C.R.S., a utility may issue, renew, extend or assume liability on securities, other than stocks, with a maturity date of not more than 12 months after the date of issuance, whether secured or unsecured, without application to or order of the Commission provided that no such securities so issued shall be refunded, in whole or in part, by any issue of securities having a maturity of more than 12 months except on application to and approval of the Commission.
- (i) Any security requiring Commission approval, but issued or assumed without such approval, shall be void.

**4106. Flexible Regulation to Provide Jurisdictional Service Without Reference to Tariffs.**

- (a) A utility seeking authority to provide a jurisdictional service without reference to a tariff shall file an application pursuant to this rule. A utility cannot provide a jurisdictional service without reference to a tariff without authority from the Commission.
- (b) An application for flexible regulation to provide jurisdictional service without reference to tariffs shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) all information required in paragraphs 4002(b) and 4002(c);
  - (II) the name of the customer or potential customer;
  - (III) a description of the jurisdictional service or services which the applying utility seeks to provide to a customer or a potential customer;
  - (IV) a description of the manner in which the applying utility will provide the jurisdictional service or services if it contracts with a customer or potential customer;
  - (V) the facts (not in conclusory form) which the applying utility believes satisfy the requirements of § 40-3-104.3(1)(a), C.R.S.; and
  - (VI) a statement that the applying utility has provided, or will provide when available, the application and contract as required by paragraph 4106(c) of this rule.
- (c) The contract which is the subject of the application shall be filed when available with the Commission under seal pursuant to rules 1100 through 1102 and § 40-3-104.3(1)(b), C.R.S. The applying utility shall furnish the application and, when it is available, the contract, under seal, to the OCC. Unless the applying utility requests other treatment, the Commission and the OCC shall treat the contract as confidential. If the Commission grants a protective order preserving the confidentiality of the contents of an application, then the applying utility shall also furnish a non-confidential version of the application without the contract to any utility then providing service to the customer or potential customer.

- (d) The direct testimony and attachments to be offered at hearing shall accompany the application unless the applying utility believes that the application will be uncontested and unopposed. If an attachment is large or cumbersome, the applying utility shall file the attachment with the Commission; shall provide, for the benefit of the intervenors, the title of the attachment and a summary of the information contained in the attachment; and shall state the location (other than the Commission) at which parties may inspect the attachment.
- (e) Pre-filed testimony or attachments shall not be modified once filed unless the modification is to correct typographical errors or misstatements of fact or unless all parties to the proceeding agree to the modification. In the event a substantive modification is made without the agreement of all parties, the Commission may allow the modification only upon a showing of good cause. The Commission may consider the effect of the substantive modification as a basis for a motion to continue in order to allow the Commission staff or any other party a reasonable opportunity to investigate and, if necessary, to address the modification.
- (f) The Commission shall provide notice of the application. Any person desiring to intervene in a proceeding initiated pursuant to § 40-3-104.3, C.R.S., and this rule shall move to do so within five days of the date the Commission provides notice.
- (g) Within five days of receiving written notice of an intervention in a proceeding initiated pursuant to § 40-3-104.3, C.R.S., and this rule, the applying utility shall hand-deliver or otherwise provide to the intervenor a non-confidential version of the application and the applying utility's pre-filed testimony and attachments.
- (h) Unless the Commission orders otherwise, the applying utility shall publish notice of the application in a newspaper of general circulation within three days of the filing of the application.
- (i) In addition to the requirements of subparagraphs 4002(d)(I) – (XII), the notice provided by the applying utility shall contain the following information:
  - (I) the address of the applying utility;
  - (II) the name of the customer(s) or potential customer(s) involved;
  - (III) a statement that the identified customer(s) or potential customer(s) may have the ability to provide its/their own service or may have competitive alternatives available to it/them;
  - (IV) a general description of the jurisdictional services to be provided;
  - (V) a statement of where affected customers may call to obtain information concerning the application and;
  - (VI) a statement that anyone desiring to participate as a party must file a petition to intervene within five days from the date of Commission notice of the application and that the intervention must comport with the Commission's Rules Regulating Practice and Procedure.
- (j) Within three days of providing notice, the applying utility shall file with the Commission an affidavit showing proof of publication of notice.

- (k) On a case-by-case basis, the Commission may require the applying utility to provide additional information.
- (l) Should an application be filed which the Commission determines is not complete, the Commission or Commission staff shall notify the applying utility within seven days from the date the application is filed of the need for additional information. The applying utility may then supplement the application so that it is complete. Once the application is complete, the Commission will process the application, with all applicable timelines running from the date the application is completed.
- (m) The Commission shall issue an order approving or disapproving the application within the time permitted under § 40-3-104.3(1)(b), C.R.S.
- (n) At the time of any proceeding in which a utility's overall rate levels are determined, the Commission may require the utility to file a fully distributed cost method which segregates investments, revenues, and expenses associated with jurisdictional utility service provided pursuant to any contract approved under this rule 4106 from other regulated utility operations in order to ensure that jurisdictional utility service provided pursuant to contract is not subsidized by revenues from other regulated utility operations.
- (o) The applying utility shall provide final contract or other description of the price and terms of service as specified in § 40-3-104.3(1)(e), C.R.S.

**4107. [Reserved].**

**4108. Tariffs.**

- (a) A utility shall keep on file with the Commission the following documents pertaining to gas sales service and gas transportation service: its current Colorado tariffs, forms of contracts (including gas sales agreements), and those gas transportation service agreements which are not the same as the standard gas transportation service agreement contained in the utility's tariffs. These documents, unless filed under seal, shall be available for public inspection at the Commission and at the principal place of business of the utility.
- (b) All tariffs shall comply with rule 1210 of the Commission's Rules of Practice and Procedure.
- (c) Filing and contents of tariff.
  - (l) In addition to the requirements and contents in rule 1210, the following shall be included in a utility's tariff as applicable:
    - (A) a description of the minimum heating value for gas service as required by paragraph 4202(a);
    - (B) a description of testing methods for gas quality as required by paragraph 4202(f);
    - (C) interruption and curtailment criteria, policies, and implementation priorities, as required by rule 4203;

- (D) transportation service rates, terms, and conditions, as required by rule 4205;
- (E) the utility's transportation service request form as required by paragraph 4206(a);
- (F) information regarding the utility's meter testing equipment and facilities, scheduled meter testing, meter testing records, fees for meter testing upon request, and meter reading, as required by rules 4303, 4304, 4305, 4306, and 4309;
- (G) information regarding benefit of service transfer policies as required by paragraph 4401(c);
- (H) information regarding installment payment plans and other plans, as required by rule 4404;
- (I) information regarding collection fees or miscellaneous service charges, as required by subparagraph 4404(c)(VI) and (c)(VIII).
- (J) information regarding any after-hour restoration fees, as required by paragraph 4409(b); and
- (K) all other rules, regulations, and policies covering the relations between the customer and the utility.

**4109. New or Changed Tariffs.**

- (a) A utility shall file with the Commission any new or changed tariffs. No new or changed tariff shall be effective unless it is filed with the Commission and either is allowed to go into effect by operation of law or is approved by the Commission.
- (b) A utility shall use one of the following processes to seek to add a new tariff or to change an existing tariff:
  - (I) The utility may file the proposed tariff, including the proposed effective date, accompanied by an advice letter pursuant to rule 1210. The utility shall provide notice in accordance with rule 1206. If the Commission does not suspend the proposed tariff in accordance with rule 1305 prior to the tariff's proposed effective date, the proposed tariff shall take effect on the proposed effective date.
  - (II) The utility may file an application to implement a proposed tariff on less than 30-days' notice, accompanied by the proposed tariff, including the proposed effective date. The utility shall provide notice in accordance with rule 1207. The application shall include the information required in paragraphs 4002(b) and 4002(c); shall explain the details of the proposed tariff, including financial data if applicable; shall state the facts which are the basis for the request that the proposed tariff become effective on less than 30-days' notice; and shall identify any prior Commission action, in any proceeding, pertaining to the present or proposed tariff.

- (III) Unless the Commission orders otherwise, a utility shall be permitted to file new tariffs complying with an order of the Commission or updating adjustment clauses previously approved by the Commission on not less than two business days' notice. No additional notice beyond the tariff filing itself shall be required.

**4110. Advice Letters.**

- (a) All advice letter filings shall comply with rule 1210 of the Commission's Rules of Practice and Procedure.
- (b) In addition to the requirements and contents in rule 1210, the advice letter shall include the estimated amounts, if any, by which the utility's revenues will be affected, calculated on an annual basis.
- (c) Customer notice of advice letter. If the utility is required by statute, Commission rule or order to provide notice to its customers of the advice letter, such notice shall include the requirements of subparagraphs 4002(d)(I) – (XII).

**4111. – 4199. [Reserved]**

**FACILITIES**

**4200. Construction, Installation, Maintenance, and Operation.**

The gas plant, equipment, and facilities of a utility shall be constructed, installed, inspected, maintained, and operated in accordance with accepted engineering and gas industry practices to assure continuity of service, uniformity in the quality of service, and the safety of persons and property.

**4201. Instrumentation.**

A utility purchasing natural gas energy or receiving natural gas energy for transportation services shall install, or shall require the interconnecting pipeline to provide, such instruments or meters as may be necessary to furnish information detailing the quantity and quality of gas received into its system as necessary to maintain measurement accuracy and acceptable gas quality.

**4202. Heating Value, Purity, and Pressure.**

- (a) A utility shall establish and maintain in its tariffs a minimum heating value for its gas, expressed in British Thermal Units per standard cubic foot. The minimum heating value shall be no less than the monthly average gross heating value of gas supplied by the utility in any given service area. No deviation below this minimum shall be permitted. The utility shall determine the heating value of gas by testing gas taken from such points on the utility's system and at such test frequencies as are reasonably necessary for a proper determination. The utility shall maintain records of tests conducted to determine the heating value of gas. The results of these tests shall be stated in terms of standard conditions.
- (b) A change in minimum heating value shall require an appropriate adjustment, if any, to rates.

- (c) The utility shall insure that the gas it supplies, if from multiple sources or if the supply from a single source changes in composition, is interchangeable for safe and efficient use. The utility shall insure that gas from new supply sources or from supply sources which the gas composition has changed is interchangeable with the gas it currently supplies. The utility shall evaluate interchangeability by means of one of the following:
  - (I) use of test results which establish that the gas supplied to the end-user falls within an acceptable range and which take into account the heating value, specific gravity, and composition of the gas;
  - (II) use of actual appliances to determine acceptability; or
  - (III) use of a standard in the natural gas industry.
- (d) A utility shall promptly readjust its customers' appliances and devices as necessary to render proper service if the readjustment is required for safe and efficient use in accordance with paragraph (c) of this rule. Unless otherwise ordered by the Commission, a readjustment made pursuant to this paragraph shall be done at no charge to the customer. If a utility determines that a readjustment pursuant to this paragraph is necessary, the utility shall notify the Commission, in writing, of the readjustment and of the reason for the readjustment.
- (e) A utility whose gas delivery exceeds 20 million cubic feet per annum shall test the heating value of gas at least once each week, unless the utility purchases or receives gas on a heat value basis or unless the interconnecting pipeline provides the utility with a record of the heating value of the gas delivered and the interconnecting pipeline's tests are made at least once each week.
- (f) All gas supplied to customers shall be substantially free of impurities which may cause corrosion of facilities or which may form corrosive or harmful fumes when burned in a properly-designed and properly-adjusted burner.
- (g) A LDC shall deliver gas at a pressure of six inches water column, plus or minus two inches water column, measured at the meter outlet, unless operating conditions require a higher delivery pressure. If a higher pressure is required, the utility shall require the customer to install appropriate pressure regulating equipment in the customer's lines, if necessary.
- (h) A utility shall monitor distribution pressure as follows:
  - (I) In a distribution system serving 100 or fewer customers, the utility shall semi-annually check distribution pressures by indicating gauges at the district regulator station or other appropriate point in the distribution system.
  - (II) In distribution system serving more than 100 and fewer than 500 customers, the utility shall provide at least one recording pressure gauge or telemetering pressure device at the pressure regulating station or at some other appropriate point in the distribution system.

(III) In a distribution system serving 500 or more customers, the utility shall maintain one or more additional recording pressure gauges or telemetering pressure devices and shall make frequent 24-hour records of the gas pressure prevailing at appropriate points in the system.

(i) In its tariff, a utility shall include a description of test methods, equipment, and frequency of testing used to determine the quality and pressure of gas service furnished.

**4203. Interruptions and Curtailments of Service.**

(a) A utility shall keep a record of all interruptions and curtailments of service on its entire system or on major divisions of its system, including a statement of the time, duration, and cause of each interruption or curtailment. A utility shall also keep a record of the time of starting up or shutting down of the compressing equipment and the period of operation of all regulators used for the maintenance of constant gas pressure.

(b) In its tariff a utility shall establish specific terms and conditions for interruptions and curtailments of service. The utility shall establish, and adhere to, interruption and curtailment priorities for sales service and for transportation service by customer class. These priorities shall be consistent with the requirements of this rule.

(c) A utility shall interrupt service within each class on an equitable basis, consistent with system constraints and its tariff. A utility shall interrupt service within a locale on a fair and reasonable basis, consistent with local conditions.

(d) A utility shall not make up any shortage by using the transportation customer's supplies without the transportation customer's consent.

(e) A utility shall curtail standby supply service to transportation customers who have contracted for standby supply service in accordance with the same system of class-by-class priorities as is applicable to sales customers established by the utility's tariffs.

(f) A utility may provide, under applicable sales tariffs, available supply service to gas transportation customers who have not purchased standby supply service from the utility and are experiencing supply shortages.

**4204. [Reserved].**

**4205. Gas Transportation Service Requirements.**

(a) In its tariffs, a utility shall establish maximum rates for gas transportation service. In addition, a utility which desires price flexibility shall include its minimum rates in its tariffs. The following apply to transportation tariff rates:

(I) Maximum rates for transportation shall be based on fully allocated cost methods and shall include an allowance for return on allocated rate base equal to the last rate of return authorized by the Commission for the utility.

- (II) A utility may, at its discretion, offer natural gas transportation standby capacity service or standby supply service. A utility may require separate charges for:
  - (A) natural gas transportation standby capacity (if offered);
  - (B) standby supply (if offered);
  - (C) administration, services and facilities; and
  - (D) a utility's avoidable purchased gas commodity costs based on current market-driven gas prices.
  
- (b) In its tariffs, a utility shall establish terms and conditions for gas transportation service, including at least the following:
  - (I) all criteria for determining gas transportation capacity;
  - (II) all gas transportation costs;
  - (III) all nomination requirements;
  - (IV) all measurement and facility requirements;
  - (V) as applicable, all gas supply cost provisions;
  - (VI) all gas balancing provisions;
  - (VII) all quality of gas requirements;
  - (VIII) the utility's line extension policy;
  - (IX) the gas transportation request form required by paragraph 4206(a);
  - (X) the utility's gas transportation standard gas transportation service agreement, which shall include the statements required by paragraph 4206(d); and
  - (XI) the utility's standard agency agreement required by paragraph 4206(e).

**4206. Gas Transportation Agreements.**

- (a) When a customer requests transportation service, a utility shall provide the customer requesting transportation with the utility's gas transportation form. This form shall set out clearly the information necessary for the utility to determine whether it can provide the requested transportation.
  
- (b) In determining whether capacity is available to provide the requested transportation, a utility shall take into account all conventional methods of delivering gas through its system, including without limitation forward haul, compression, exchange, flow reversal, backhaul, and displacement. The



utility is not required to perform exchanges or displacements over segments of its system which are not physically connected.

- (c) A utility shall process, shall approve or reject, and shall provide notification of its decision with respect to a transportation request within 60 days after receiving a written request from a transportation customer. If the utility rejects the request, the utility shall provide, within three business days, written notice of its decision to the customer and shall retain a record of the rejection notice for two years. The notice shall detail the reasons for the rejection and shall explain what changes are necessary to make the request acceptable. If the request is approved, the utility shall provide, within three business days, written notification of approval to the customer.
- (d) A utility shall maintain on file with the Commission a standard gas transportation agreement. All gas transportation agreements shall contain the following provisions.
  - (I) This agreement, and all its rates, terms and conditions as set out in this agreement and as set out in the tariff provisions which are incorporated into this agreement by reference, shall at all times be subject to modification by order of the Commission upon notice and hearing and a finding of good cause therefore. In the event that any party to this agreement requests the Commission to take any action which could cause a modification in the conditions of this agreement, the party shall provide written notice to the other parties at the time of filing the request with the Commission.
  - (II) If the end-use customer uses a marketing broker for nomination, gas purchases, and balancing, the end-use customer shall provide the utility with an agency agreement.
- (e) A utility shall maintain on file with the Commission the standard agency agreement to be used when an end-use transportation customer uses a third party for any services related to nomination, gas purchases, and balancing activities.
- (f) A utility shall maintain logs showing all requests for gas transportation. The log shall contain the following information: the identity of the party making the transportation request, the date of the request, the volume requirements, duration, receipt and delivery points, type of service, and the disposition of the request. The utility shall retain these logs for two years.

**4207. Purchases Replaced by Transportation.**

- (a) Any reduction of gas purchases by a current sales customer who replaces sales purchases with transportation directly reduces a utility's obligation to provide gas to that customer on both a peak day and on an annual volume basis. If offered by the utility, a customer may retain rights to gas supplies by electing to pay for standby capacity service and standby supply service.
- (b) Any reduction of gas purchases by a current interruptible sales customer who replaces said purchases with transportation gas directly reduces the utility's obligation to provide gas supplies to that customer on an annual volume basis. At the discretion of the utility, a customer may retain rights to interruptible gas supplies by electing to pay for standby supply service.

- (c) If a sales customer converts all, or a portion, of its service to transportation and if it does not elect standby supply service, then the customer must reapply for sales service in the future if it wishes to convert the transportation portion of its service back to sales service.
- (d) The utility shall have no sales service obligation to a transportation customer who is solely responsible for procuring its own gas supply. The customer may retain rights to gas supplies by electing to pay for standby supply service.

**4208. Anticompetitive Conduct Prohibited.**

- (a) A utility shall apply all transportation rates and policies without undue discrimination or preference to its affiliates. Each contract to transport gas for a marketing or brokering affiliate of a utility shall be an arm's-length agreement containing only terms which are available to other transportation customers.
- (b) A utility is prohibited from engaging in anticompetitive conduct, discriminatory behavior, and preferential treatment in transporting gas, including (without limitation) the following:
  - (I) disclosure to a marketing or brokering affiliate of confidential information provided by nonaffiliated transportation customers;
  - (II) disclosing to any transportation customer the utility's own confidential information unless the same information is communicated contemporaneously to all current transportation customers;
  - (III) disclosing to any transportation customer of information filed with a transportation request unless the same information is communicated contemporaneously to all current transportation customers;
  - (IV) providing any false or misleading information, or failing to provide information, regarding the availability of capacity for transportation service;
  - (V) tying an agreement to release gas to an agreement by the transportation customer to obtain services from a marketing or brokering affiliate of the utility or to an offer by the utility to provide or to expedite transportation service to its affiliate for the released gas;
  - (VI) providing any false or misleading information, or failing to provide information, about gas releases;
  - (VII) failing to notify all affiliate brokers and marketers and all transportation customers of gas releases at the same time and in the same manner or otherwise allowing marketing or brokering affiliates preferential access to released gas;
  - (VIII) lending gas to a marketing or brokering affiliate to meet balancing requirements except under terms available to other transportation customers;
  - (IX) directing potential customers to the utility's own marketing or brokering affiliate, but the utility may provide a list of all registered gas marketers and brokers, including its affiliates;

- (X) charging lower rates to a transportation customer conditioned on the purchase of gas from the utility's marketing or brokering affiliate;
- (XI) conditioning the availability of transportation service upon the use of the utility's marketing or brokering affiliate;
- (XII) providing exchange or displacement services to one transportation customer without providing them to others on the same terms and conditions;
- (XIII) giving its marketing affiliate preference over nonaffiliated customers in matters relating to transportation including, but not limited to, scheduling, balancing, transportation, storage, or curtailment priority;
- (XIV) disclosing to its affiliate any information the utility received from a nonaffiliated transportation customer or potential nonaffiliated transportation customer;
- (XV) failing contemporaneously to provide identical gas transportation sales or marketing information it provides to a marketing affiliate to all potential transportation customers, affiliated and nonaffiliated, on its system; and
- (XVI) failing to make available to all similarly-situated nonaffiliated transportation customers discounts which are comparable to those made to an affiliated marketer.

**4209. [Reserved].**

**4210. Line Extension.**

- (a) A utility shall have tariffs which set out its line extension policies, procedures, and conditions.
- (b) In its tariff a LDC shall include the following provisions for gas main extensions and service lateral extensions from its distribution system:
  - (I) the terms and conditions, by customer class, under which an extension will be made;
  - (II) provisions requiring the utility to provide to a customer or to a potential customer, upon request, service lateral connection information necessary to allow the customer's or potential customer's facilities to be connected to the utility's system;
  - (III) provisions requiring the utility to exercise due diligence in providing the customer or potential customer with an estimate of the anticipated cost of a connection or extension; and
  - (IV) provisions addressing steps to ameliorate the rate and service impact upon existing customers, including stating in the tariff the procedures by which future customers would share costs incurred by the initial or existing customers served by a connection or extension (as, for example, by including the procedures by which a refund of customer connection or extension payments would be made when appropriate).

**4211. – 4299. [Reserved].**

## **METERS**

### **4300. Service Meters and Related Equipment.**

- (a) All meters used in connection with gas metered service for billing purposes shall be furnished, installed, and maintained by the utility.
- (b) All equipment, devices, or facilities (including, without limitation, service meters) furnished by the utility and which the utility maintains and renews shall remain the property of the utility and may be removed by it at any time after discontinuance of service.
- (c) Each service meter shall indicate clearly the cubic feet or other units of service for which the customer is charged for service through each meter. In cases in which the dial reading of a meter, other than an orifice or other chart type meter, must be multiplied by a constant or factor to obtain the units consumed, the factor, factors, or constant shall be clearly marked on the dial or face of the meter, if possible. In the alternative, the constant, constants, or factor, or the method of calculating the constant, constants, or factor, shall be stated clearly on a customer's bill, with step by step instructions to allow customer to convert the unit of measurement from the dial of the meter to the billing unit or billing determinant on the bill.

### **4301. Location of Service Meters.**

- (a) As of the time of installation, meters shall be located in accordance with the pertinent utility tariffs and in accordance with accepted safe practice and gas utility industry standards.
- (b) As of the time of installation, meters shall be located so as to be easily accessible for reading, testing, and servicing in accordance with accepted safe practice and in accordance with gas utility industry standards.

### **4302. Service Meter Accuracy.**

- (a) Before being installed for use by a customer, every gas service meter, whether new, repaired, or removed from service for any cause shall be in good order and, except as provided in paragraph (b) of this rule, shall be adjusted to be correct to within one percent when passing gas at 20 percent of its rated capacity at one-half inch water column differential.
- (b) New rotary displacement type gas service meters in sizes having a rated capacity of more than 5,000 cubic feet per hour at a differential not to exceed two inches water column shall be tested and calibrated at the factory in accordance with recognized and accepted practices. These meters shall also be adjusted to be correct within two percent slow and one percent fast when passing gas at ten percent of its rated capacity and shall be adjusted to be correct within one percent slow and one percent fast when passing gas at 100 percent of its rated capacity. Prior to reuse of a rotary displacement type meter that has been removed from service, the meter shall pass the same testing criteria as a new meter.

### **4303. Meter Testing Equipment and Facilities.**

- (a) A utility shall provide, or shall arrange for a qualified third party to provide, such equipment and facilities as may be necessary to make the tests and to provide the service required. Such

equipment and facilities shall be available at all reasonable times for inspection by Commission staff.

- (b) A utility having more than 200 meters in service shall maintain, or shall require the qualified third party that provides meter testing equipment and facilities to maintain, suitable gas meter testing equipment in proper adjustment so as to register the condition of meters tested within one-half of one percent. The utility shall have and shall maintain, for the testing equipment, necessary certificate(s) of calibration showing that the equipment has been tested with a standard certified by the National Institute of Standards and Technology or other laboratory of recognized standing.
- (c) In its tariff, a utility shall include a description of its meter testing equipment and of the methods employed to ascertain and to maintain accuracy of all testing equipment.
- (d) A utility shall keep records of certification and calibrations for all testing equipment required by this rule for the life of the equipment.

**4304. Scheduled Meter Testing.**

- (a) A utility shall test, or shall arrange for testing of, service meters in accordance with the schedule in this rule or in accordance with a sampling program approved by the Commission.
- (b) If it wishes to use a sampling program, a utility shall file an application to request approval of a sampling program. The application shall include:
  - (I) the information required by paragraphs 4002(b) and 4002(c);
  - (II) a description of the sampling program which the utility wishes to use. This description shall include, at a minimum the following:
    - (A) the type(s) of meters subject to the sampling plan;
    - (B) the frequency of testing;
    - (C) the procedures to be used for the sampling;
    - (D) the meter test method to be used;
    - (E) the accuracy of the testing and of the sampling plan;
    - (F) an explanation of the reason(s) for the requested sampling program; and
    - (G) an analysis which demonstrates that, with respect to assuring the accuracy of the service meters tested, the requested sampling program is at least as effective as the schedule in this rule.
- (c) Revisions to any portion of a sampling program approved pursuant to the procedure in paragraph (b) of this rule shall be accomplished by the filing of, and Commission approval of, a new application.

- (d) Every service meter shall be tested and adjusted before installation to ensure that it registers accurately and conforms with the requirements of rule 4302. In addition, every service meter shall be tested on a periodic basis, as follows:
  - (I) diaphragm type gas service meter in sizes having rated capacity of 800 cubic feet or less per hour at one-half inch water column differential, every six years;
  - (II) diaphragm type gas service meter in sizes having a rated capacity of more than 800 cubic feet per hour at one-half inch water column differential, every five years;
  - (III) rotary displacement type gas service meter in sizes having a rated capacity of 5,000 cubic feet or less per hour at one-half inch water column differential, every five years;
  - (IV) rotary displacement type gas service meters in sizes having a rated capacity of more than 5,000 cubic feet per hour at a differential not to exceed two inches water column, the frequency of testing stated in the utility's tariff;
  - (V) orifice meters, not less than once each year; and
  - (VI) meter types not listed, not less than once each year.
- (e) In its tariff, a utility shall describe the utility's practices concerning the following:
  - (I) testing and adjustment of service meters at installation; and
  - (II) periodic testing after installation.

**4305. Meter Testing Upon Request.**

- (a) If a customer disputes the accuracy of a meter or disputes the billing that implicates the accuracy of a meter, the utility furnishing metered gas service shall inform the customer of their rights to have the meter tested as specified in this rule. Within 30 days of a customer's request, the utility shall test the meter's accuracy using standardized testing equipment. The test shall be conducted free of charge if the meter has not been tested within the previous 12 months; otherwise the utility may charge a fee for performing the test. The utility shall provide a written report of the test results to the customer and shall maintain the report on file for at least two years from the date of the test. If, upon completion of the test, the disputed meter is found to be inaccurate beyond the limits prescribed in rule 4302, it shall be deemed out of compliance.
- (b) Should a customer request and receive a meter test as prescribed in paragraph 4305(a) and continue to dispute the accuracy of the meter, or the billing that implicates the accuracy of the meter, the utility shall give notice to the customer of his or her right to request independent testing of the meter. The customer's right to request independent testing of the meter shall expire on the 30<sup>th</sup> day after the date of the utility's notice. Upon the customer's request, the utility shall make the disputed meter available for independent testing by a qualified meter testing facility of the customer's choosing. The customer is not entitled to take physical possession of the disputed meter. To be a qualified meter testing facility, the testing facility must be capable of testing the meter to meet all meter standards and requirements required by these rules.

- (c) If, upon completion of an independent test as prescribed in paragraph 4305(b), the disputed meter is found to be accurate within the limits of rule 4302, the customer shall bear all costs associated with conducting the independent test. If, upon completion of an independent test as prescribed in paragraph 4305(b), the disputed meter is found to be inaccurate beyond the limits prescribed in rule 4302, the meter shall be deemed out of compliance and the utility shall bear all costs associated with conducting the independent test.
- (d) In its tariff, a utility shall include any fees associated with customer-requested meter testing conducted within 12 months of a prior test.
- (e) If a meter is deemed out of compliance under this rule, the utility shall either inform the customer of his or her right to request a refund pursuant to rule 4402 or unilaterally issue the refund.

**4306. Records of Tests and Meters.**

- (a) For each meter owned or installed, a utility shall maintain a record showing the date of purchase, the manufacturer's serial number, the record of the present or previously installed location, and the date and results of the last test performed by the utility. This record shall be retained for the life of the meter plus 30 months.
- (b) Whenever a meter is tested either on request or upon complaint, the test record shall include the information necessary for identifying the meter, the reason for making the test, the reading of the meter if removed from service, the result of the test, and all data taken at the time of the test in a sufficiently complete form to permit the convenient checking of the methods employed and the calculations made. This record shall be retained for at least two years.

**4307- 4308. [Reserved].**

**4309. Meter Reading.**

- (a) Upon a customer's request, a utility shall provide written documentation showing the date of the most recent reading of the customer's meter and the total usage expressed in cubic feet or other unit of service recorded. On request, a utility supplying metered service shall explain to a customer in a clear non-technical statement its method of reading the customer's meter.
- (b) A utility shall include in its tariff a clear statement describing when meters will be read by the utility and the circumstances, if any, under which the customer must read the meter and submit the data to the utility. This statement shall specify in detail the procedure that the customer must follow and shall specify all special conditions that apply to each class of service.
- (c) Absent good cause, a utility shall read a meter monthly. For good cause shown, a utility shall read a meter at least once every six months.

**4310. – 4399. [Reserved]**

## **BILLING AND SERVICE**

### **4400. Applicability.**

Rules 4400 through 4412 apply to residential customers, small commercial customers and agricultural customers served pursuant to a LDC's rates or tariffs. Rules 4400 through 4405 and rules 4407 through 4412 shall not apply to customers served under a LDC's transportation rates or tariffs. In its tariffs, a LDC shall define "residential," "small commercial" and "agricultural" customers to which these rules apply. The LDC may elect to apply the same or different terms and conditions of service to other customers.

### **4401. Billing Information and Procedures.**

- (a) All bills issued to customers for metered service furnished shall show:
- (I) the dates and meter readings beginning and ending the period during which service was rendered;
  - (II) an appropriate rate or rate code identification for each separate rate component charged to the bill. Each component shall be designated on the bill in a manner such that the rate or charge can be identified clearly when referencing approved rates found in the utility's tariff;
  - (III) the net amount due for regulated charges;
  - (IV) the date by which payment is due, which shall not be earlier than 15 days after the mailing or the hand-delivery of the bill;
  - (V) a distinct marking to identify an estimated bill;
  - (VI) the total amount of all payments or other credits made to the customer's account during the billing period;
  - (VII) any past due amount. Unless otherwise stated in a tariff or Commission rule, an account becomes "past due" on the 31st day following the due date of current charges;
  - (VIII) the identification of, and amount due for, unregulated charges, if applicable;
  - (IX) any transferred amount or balance from any account other than the customer's current account; and
  - (X) all other essential facts upon which the bill is based, including factors and constants, as applicable.
- (b) A utility that bills for unregulated services or goods shall allocate partial payments first to regulated charges and then to unregulated charges or non-tariff charges and to the oldest balance due separately within each category.



- (c) A utility that transfers to a customer a balance from the account of a person other than that customer shall have in its tariffs the utility's benefit of service transfer policies and criteria. The tariffs shall contain an explanation of the process by which the utility will verify, prior to billing a customer under the benefit of service tariff, that the person to be billed in fact received the benefit of service.
- (d) A utility may transfer a prior unpaid debt to a customer's bill if the prior bill was in the name of the customer and the utility has informed the customer of the transferred amount and of the source of the unpaid debt (for example, and without limitation, the address of the premises to which service was provided and the period during which service was provided).
- (e) If it is offered in a tariff, upon request from a customer and where it is technically feasible, a utility may have the option to provide electronic billing (e-billing), in lieu of a printed bill, to the requesting customer. If a utility offers the option of e-billing, the following shall apply:
  - (I) the utility shall obtain the affirmative consent of a customer to accept such a method of billing in lieu of printed bills;
  - (II) the utility shall not charge a fee for billing through the e-billing option;
  - (III) the utility shall not charge a fee based on customer payment options that is different from the fee charged for the use of the same customer payment options by customers who receive printed bills; and
  - (IV) a bill issued electronically shall contain the same disclosures and Commission-required information as those contained in the printed bill provided to other customers.

**4402. Adjustments for Meter and Billing Errors.**

- (a) A utility shall adjust a customer's bill(s) for gas incorrectly metered or billed as follows.
  - (I) When, upon any meter accuracy test, a meter is found to be running slow in excess of error tolerance levels allowed under rule 4302, the utility may charge for one-half of the under-billed amount for the period dating from the discovery of the meter error back to the previous meter test, with such period not to exceed six months.
  - (II) When, upon any meter accuracy test, a meter is found to be running fast in excess of error tolerance levels allowed under rule 4302, the utility shall refund one-half of the excess charge for the period dating from the discovery of the meter error back to the previous meter test, with such period not to exceed two years.
  - (III) When a meter does not register, registers intermittently, or partially registers for any period, the utility may estimate, using the method stated in its tariff, a charge for the gas used based on amounts metered to the customer over a similar period in previous years. The period for which the utility charges the estimated amount shall not exceed six months.

- (IV) In the event of under-billings not provided for in subparagraph (a)(I) or (III) of this rule (such as, but not limited to, an incorrect multiplier, an incorrect register, or a billing error), the utility may charge for the period during which the under-billing occurred, with such period not to exceed six months.
- (V) In the event of over-billings not provided for in subparagraph (a)(II) of this rule, the utility shall refund for the period during which the over-billing occurred, with such period not to exceed two years.
- (b) The periods set out in paragraph (a) of this rule shall commence on the earliest date on which either the customer notifies the utility or the utility notifies the customer of a meter or billing error, the customer informs the utility of a billing or metering error, or a dispute based on a billing or metering error, or the customer submits an informal complaint to the Consumer Assistance Unit of the Commission. <http://www.colorado.gov/pacific/dora/file-consumer-complaint>.
- (c) In the event of an over-billing, the customer may elect to receive the refund as a credit to future billings or as a one-time payment. If the customer elects a one-time payment, the utility shall make the refund within 30 days. Such over-billings shall not be subject to interest.
- (d) In the event of under-billing, the customer shall be eligible and may elect to enter into a payment arrangement on the under-billed amount. The payment arrangement shall be equal in length to the length of time during which the under-billing occurred. Such under-billings shall not be subject to interest.

**4403. Applications for Service, Customer Deposits, and Third-Party Guarantee Arrangements.**

- (a) A utility shall process an application for utility service which is made either orally or in writing and shall apply nondiscriminatory criteria with respect to the requirement of a deposit prior to commencement of service.
- (b) If billing records are available for a customer who has received past service from the utility, the utility shall not require that person to make new or additional deposits to guarantee payment of current bills unless the records indicate recent or substantial delinquencies. All customers shall be treated without undue discrimination with respect to deposit requirements, and such requirements shall be specifically stated in to the utility's tariff.
- (c) A utility shall not require a deposit from an applicant for service who provides written documentation of a 12 consecutive month good credit history from the utility from which that person received similar service. For purposes of this paragraph, the 12 consecutive months must have ended no earlier than 60 days prior to the date of the application for service.
- (d) If a utility uses credit scoring to determine whether to require a deposit from an applicant for service or a customer, the utility shall have a tariff which describes, for each scoring model that it uses, the credit scoring evaluation criteria and the credit score limit which triggers a deposit requirement.
- (e) All utilities requiring deposits shall offer customers at least one non-cash alternative that does not require the use of the customer's social security number, in lieu of a cash deposit.

- (f) If a utility uses credit scoring, prior payment history with the utility, or customer-provided prior payment history with a like utility as a criterion for establishing the need for a deposit, the utility shall include in its tariff the specific evaluation criteria which trigger the need for a deposit.
- (g) If a utility denies an application for service or requires a deposit as a condition of providing service, the utility immediately shall inform the applicant for service of the decision and shall provide, within three business days, a written explanation to the applicant for service stating the specific reasons the application for service has been denied or a deposit is required.
- (h) No utility shall require any surety other than either a deposit to secure payment for utility services or a third-party guarantee of payment in lieu of a deposit. In no event shall the furnishing of utility services or extension of utility facilities, or any indebtedness in connection therewith, result in a lien, mortgage, or other interest in any real or personal property of the customer unless such indebtedness has been reduced to a judgment. Should the guarantor terminate service or terminate the third party guarantee before the customer has established a satisfactory payment record for 12 consecutive months, the utility, applying the criteria contained in its tariffs, may require a deposit or a new third party guarantor.
- (i) A deposit shall not exceed an amount equal to an estimated 90 days' bill of the customer, except in the case of a customer whose bills are payable in advance of service, in which case the deposit shall not exceed an estimated 60 days' bill of the customer. The deposit may be in addition to any advance, contribution in aid of construction or guarantee required by the utility tariff in connection with construction of lines or facilities, as provided in the extension policy in the utility's tariffs.
- (j) A utility receiving deposits shall maintain records showing:
  - (I) the name of each customer making a deposit;
  - (II) the amount and date of the deposit;
  - (III) each transaction, such as the payment of interest or interest credited, concerning the deposit;
  - (IV) each premise where the customer receives service from the utility while the deposit is retained by the utility;
  - (V) if the deposit was returned to the customer, the date on which the deposit was returned to the customer; and
  - (VI) if the unclaimed deposit was paid to the energy assistance organization, the date on which the deposit was paid to the energy assistance organization.
- (k) In its tariff, a utility shall clearly state its customer deposit policy for establishing or maintaining service. The tariff shall state the circumstances under which a deposit will be required and the circumstances under which it will be returned.

- (l) A utility shall issue a receipt to every customer from whom a deposit is received. No utility shall refuse to return a deposit or any balance to which a customer may be entitled solely on the basis that the customer is unable to produce a receipt.
- (m) The payment of a deposit shall not relieve any customer from the obligation to pay current bills as they become due. A utility is not required to apply any deposit to any indebtedness of the customer to the utility, except for utility services due or past due after service is terminated.
- (n) A utility shall pay simple interest on a deposit at the percentage rate per annum as calculated by the Commission staff and in the manner provided in this paragraph.
  - (I) At the request of the customer, the interest shall be paid to the customer either on the return of the deposit or annually. The simple interest on a deposit shall be earned from the date the deposit is received by the utility to the date the customer is paid. At the option of the utility, interest payments may be paid directly to the customer or credited to the customer's account.
  - (II) The simple interest to be paid on a deposit during any calendar year shall be at a rate equal to the average for the period October 1 through September 30 (of the immediately preceding year) of the 12 monthly average rates of interest expressed in percent per annum, as quoted for one-year United States Treasury constant maturities, as published in the Federal Reserve Bulletin, by the Board of Governors of the Federal Reserve System. Each year, the Commission staff shall compute the interest rate to be paid. If the difference between the existing customer deposit interest rate and the newly calculated customer deposit interest rate is less than 25 basis points, the existing customer deposit interest rate shall continue for the next calendar year. If the difference between the existing customer deposit interest rate and the newly calculated customer deposit interest rate is 25 basis points or more, the newly calculated customer deposit interest rate shall be used. The Commission shall send a letter to each utility stating the rate of interest to be paid on deposits during the next calendar year. Annually following receipt of Commission staff's letter, if necessary, a utility shall file by advice letter or application, as appropriate, a revised tariff, effective the first day of January of the following year, or on an alternative date set by the Commission, containing the new rate of interest to be paid upon customers' deposits, except when there is no change in the rate of interest to be paid on such deposits.
- (o) A utility shall have tariffs concerning third-party guarantee arrangements and, pursuant to those tariffs, shall offer the option of a third party guarantee arrangement for use in lieu of a deposit. The following shall apply to third-party guarantee arrangements:
  - (I) an applicant for service or a customer may elect to use a third-party guarantor in lieu of paying a deposit;
  - (II) the third-party guarantee form, signed by both the third-party guarantor and the applicant for service or the customer, shall be provided to the utility;
  - (III) the utility may refuse to accept a third-party guarantee if the guarantor is not a customer in good standing at the time of the presentation of the guarantee to the utility;

- (IV) the amount guaranteed shall not exceed the amount which the applicant for service or the customer would have been required to provide as a deposit;
  - (V) the guarantee shall remain in effect until the earlier of the following occurs:
    - (A) the guarantee is terminated in writing by the guarantor;
    - (B) if the guarantor was a customer at the time of undertaking the guarantee, the guarantor ceases to be a customer of the utility; or
    - (C) the customer has established a satisfactory payment record, as defined in the utility's tariffs, for 12 consecutive months.
  - (VI) Should the guarantor terminate service or terminate the third party guarantee before the customer has established a satisfactory payment record for 12 consecutive months, the utility, applying the criteria contained in its tariffs, may require a deposit or a new third party guarantor.
- (p) A utility shall pay all unclaimed monies, as defined in § 40-8.5-103(5), C.R.S., that remain unclaimed for more than two years to the energy assistance organization. "Unclaimed monies" shall not include undistributed refunds for overcharges subject to other statutory provisions and rules and credits to existing customers from cost adjustment mechanisms.
- (I) Monies shall be deemed unclaimed and presumed abandoned when left with the utility for more than two years after termination of the services for which the deposit or the construction advance was made or when left with the utility for more than two years after the deposit or the construction advance becomes payable to the customer pursuant to a final Commission order establishing the terms and conditions for the return of such deposit or advance and the utility has made reasonable efforts to locate the customer.
  - (II) Interest on a deposit shall accrue at the rate established pursuant to paragraph (n) of this rule commencing on the date on which the utility receives the deposit and ending on the date on which the deposit is paid to the energy assistance organization. If the utility does not pay the unclaimed deposit to the energy assistance organization within four months of the date on which the unclaimed deposit is deemed to be unclaimed or abandoned pursuant to subparagraph (p)(I) of this rule, then at the conclusion of the four-month period, interest shall accrue on the unclaimed deposit at the rate established pursuant to paragraph (n) of this rule plus six percent.
  - (III) If payable under the utility's line extension tariff provisions, interest on a construction advance shall accrue at the rate established pursuant to paragraph (n) of this rule commencing on the date on which the construction advance is deemed to be owed to the customer pursuant to the utility's extension policy and ending on the date on which the construction advance is paid to the energy assistance organization. If the utility does not pay the unclaimed construction advance to the energy assistance organization within four months of the date on which the unclaimed construction advance is deemed to be unclaimed or abandoned pursuant to subparagraph (p)(I) of this rule, then at the conclusion of the four-month period, interest shall accrue on the unclaimed construction advance at the rate established pursuant to paragraph (n) of this rule plus six percent.

- (q) A utility shall resolve all inquiries regarding a customer's unclaimed monies and shall not refer such inquiries to the energy assistance organization.
- (r) If a utility has paid unclaimed monies to the energy assistance organization, a customer later makes an inquiry claiming those monies, and the utility resolves the inquiry by paying those monies to the customer, the utility may deduct the amount paid to the customer from future funds submitted to the energy assistance organization.

**4404. Installment Payments.**

- (a) A utility shall make a budget or level payment plan available for its customers and have such plan clearly defined in its tariff.
- (b) A utility shall have in its tariff an installment payment plan which permits a customer to make installment payments if one of the following applies.
  - (I) The plan is to pay regulated charges from past billing periods and the past due amount arises solely from events under the utility's control (such as, without limitation, meter malfunctions, billing errors, utility meter reading errors, or failures to read the meter, except where the customer refuses to read the meter and it is not readily accessible to the utility). A utility shall advise a customer who is eligible for this type of plan of the customer's eligibility. At the request of the customer and at the customer's discretion, an installment payment plan under this subparagraph shall extend over a period equal in length to that during which the errors were accumulated and shall not include interest.
  - (II) The customer pays at least ten percent of the amount shown on the notice of discontinuance for regulated charges and enters into an installment payment plan on or before the expiration date of the notice of discontinuance.
  - (III) The customer pays at least ten percent of any regulated charges amount more than 30 days past due and enters into an installment payment plan on or before the last day covered by a medical certification. A customer who has entered into and failed to abide by an installment payment plan prior to receiving a medical certification shall pay all amounts that were due for regulated charges up to the date on which the customer presented a medical certification which meets the requirements of subparagraph 4407(e)(IV) and then may resume the installment payment plan.
  - (IV) If service has been disconnected, the customer pays at least any collection and reconnection charges and enters into an installment payment plan. This subparagraph shall not apply if service was discontinued because the customer breached a prior payment arrangement.
- (c) Installment payment plans shall include the following amounts that are applicable at the time the customer requests a payment arrangement:
  - (I) the unpaid remainder of amounts due for regulated charges shown on the notice of discontinuance;

- (II) any amounts due for regulated charges not included in the amount shown on the notice of discontinuance which have since become more than 30 days past due;
  - (III) all current regulated charges contained in any bill which is past due but is less than 30 days past the due date;
  - (IV) any new regulated charges contained in any bill which has been issued but is not past due;
  - (V) any regulated charges which the customer has incurred since the issuance of the most recent monthly bill;
  - (VI) any collection fees as provided for in the utility's tariff, whether or not such fees have appeared on a regular monthly bill;
  - (VII) any deposit, whether already billed, billed in part, or required by the utility's tariff, due for discontinuance or delinquency or to establish initial credit, other than a deposit required as a condition of initiating service; and
  - (VIII) any other regulated charges or fees provided in the utility's tariff (including without limitation miscellaneous service charges, investigative charges, and checks returned for insufficient funds charges), whether or not they have appeared on a regular monthly bill.
- (d) Within seven calendar days of entering into a payment arrangement with a customer, a utility shall provide the customer with this rule and a statement describing the payment arrangement. The statement describing the payment arrangement shall include the following:
- (I) the terms of the payment plan; and
  - (II) a description of the steps which the utility will take if the customer does not abide by payment plan.
- (e) Except as provided in subparagraph (b)(l) of this rule, an installment payment plan shall consist, at a minimum, of equal monthly installments for a term selected by the customer but not to exceed six months. In the alternative, the customer may choose a modified budget billing, level payment, or similar tariff payment arrangement in which the total due shall be added to the preceding year's total billing to the customer's premises, modified for any base rate or cost adjustment changes. The resulting amount shall be divided and billed in 11 equal monthly budget billing payments, followed by a settlement billing in the twelfth month, or shall follow other payment-setting practices consistent with the tariff plan available.

- (f) For an installment payment plan entered into pursuant to this rule, the first monthly installment payment, and with the new charges (unless the new charges have been made part of the arrangement amount) shall be due on a date which is not earlier than the next regularly-scheduled due date of the customer who is entering into the installment payment plan. Succeeding installment payments, together with the new charges, shall be due in accordance with the due date established in the installment payment plan. Any payment not made on the due date established in the installment payment plan shall be considered in default. Any new charges that are not paid by the due date shall be considered past due, excluding those circumstances covered in subparagraph (b)(I) of this rule.
- (g) This rule shall not be construed to prevent a utility from offering any other installment payment plan terms to avoid discontinuance or terms for restoration of service, provided the terms are at least as favorable to the customer as the terms set out in this rule.

**4405. Service, Rate, and Usage Information.**

- (a) In addition to the requirement found in rule 1206, a utility shall inform its customers of any change proposed or made in any term or condition of its service if that change or proposed change will affect the quality of the service provided.
- (b) A utility shall transmit information provided pursuant to this rule through the use of a method (such as, without limitation, bill inserts or periodic direct mail) that will assure receipt by each customer.
- (c) Upon request, a utility shall provide the following information to a customer.
  - (I) A clear and concise explanation of the existing rate schedule applicable to the customer, the rate components for that rate schedule, and an explanation of how those components are calculated and applicable to the customer. This shall be provided within ten days of a customer's request or, in the case of a new customer, within 60 days of the commencement of service.
  - (II) A clear and concise statement of the customer's actual consumption or degree-day adjusted consumption of gas for each billing period during the prior year, unless such consumption data are not reasonably ascertainable by the utility.
  - (III) A clear and concise explanation of the terms and conditions of service applicable to the customer.

**4406. Itemized Billing Components.**

- (a) A utility shall provide itemized gas cost information to all customers commencing with the first complete billing cycle in which the new rates are in effect. The information may be provided in the form of a bill insert or a separate mailing.
- (b) The information provided pursuant to this rule shall include the following:
  - (I) the per-unit and fixed service rates to be billed to the customer;



- II) the per-unit and monthly gas commodity costs for that customer;
- (III) the per-unit and monthly costs of upstream services for that customer; and
- (IV) the monthly gas demand side management costs for that customer.

**4407. Discontinuance of Service.**

- (a) A utility shall not discontinue the service of a customer for any reason other than the following:
  - (I) nonpayment of regulated charges;
  - (II) fraud or subterfuge;
  - (III) service diversion;
  - (IV) equipment tampering;
  - (V) safety concerns;
  - (VI) discontinuance ordered by any appropriate governmental authority; or
  - (VII) properly discontinued service being restored by someone other than the utility when the original cause for proper discontinuance has not been cured.
- (b) A utility shall not discontinue service for nonpayment of any of the following:
  - (I) any amount which has not appeared on a regular monthly bill or which is not past due. Unless otherwise stated in a tariff or Commission rule, an account becomes "past due" on the 31st day following the due date of current charges;
  - (II) any amount due on another account now or previously held or guaranteed by the customer, or with respect to which the customer received service, unless the amount has first been transferred either to an account which is for the same class of service or to an account which the customer has agreed will secure the other account. Any amount so transferred shall be considered due on the regular due date of the bill on which it first appears and shall be subject to notice of discontinuance as if it had been billed for the first time;
  - (III) any amount due on an account on which the customer is or was neither the customer of record nor a guarantor, or any amount due from a previous occupant of the premises. This subparagraph does not apply if the customer is or was obtaining service through fraud or subterfuge or if paragraph 4401(c) applies;
  - (IV) any amount due on an account for which the present customer is or was the customer of record, if another person established the account through fraud or subterfuge and without the customer's knowledge or consent;

- (V) any delinquent amount, unless the utility can supply billing records from the time the delinquency occurred;
  - (VI) any debt except that incurred for service rendered by the utility in Colorado; or
  - (VII) any unregulated charge.
- (c) If the utility discovers any connection or device installed on the customer's premises, including any energy-consuming device in the proximity of the utility's meter, which would prevent the meter from registering the actual amount of energy used, the utility shall do one of the following.
- (I) Remove or correct such devices or connections. If the utility takes this action, it shall leave at the premises a written notice which advises the customer of the violation, of the steps taken by the utility to correct it, and of the utility's ability to bill the customer for any estimated energy consumption not properly registered. This notice shall be left at the time the removal or correction occurs.
  - (II) Provide the customer with written notice that the device or connection must be removed or corrected within 15 days and that the customer may be billed for any estimated energy consumption not properly registered. If the utility elects to take this action and the device or connection is not removed or corrected within the 15 days permitted, then within seven calendar days from the expiration of the 15 days, the utility shall remove or correct the device or connection pursuant to subparagraph (c)(I) of this rule.
- (d) If a utility discovers evidence that any utility-owned equipment has been tampered with or that service has been diverted, the utility shall provide the customer with written notice of the discovery. The written notice shall inform the customer of the steps the utility will take to determine whether non-registration of energy consumption has or will occur and shall inform the customer that the customer may be billed for any estimated energy consumption not properly registered. The utility shall mail or hand-deliver the written notice within three calendar days of making the discovery of tampering or service diversion.
- (e) A utility shall not discontinue service, other than to address safety concerns, if one of the following is met:
- (I) If a customer at any time tenders full payment in accordance with the terms and conditions of the notice of discontinuance to a utility employee authorized to receive payment. Payment of a charge for a service call shall not be required to avoid discontinuance.
  - (II) If a customer pays, on or before the expiration date of the notice of discontinuance, at least one-tenth of the amount shown on the notice and enters into an installment payment plan with the utility, as provided in rule 4404.
  - (III) If it is between 12 Noon on Friday and 8 a.m. the following Monday; between 12 Noon on the day prior to and 8:00 a.m. on the day following any state or federal holiday; or between 12 Noon on the day prior to and 8:00 a.m. on the day following any day during which the utility's local office is not open.

- (IV) Medical emergencies.
- (A) A utility shall postpone discontinuance of gas service to a residential customer for 60 days from the date of a medical certificate issued by a Colorado-licensed physician or health care practitioner acting under a physician's authority which evidences that discontinuance of service will aggravate an existing medical emergency or create a medical emergency for the customer or a permanent resident of the customer's household. The customer may receive a single 30-day extension by providing a second medical certification prior to the expiration of the original 60-day period. A customer may invoke this subparagraph 4407(e)(IV)(A) only once in any twelve consecutive months.
  - (B) As a condition of obtaining a new installment payment plan on or before the last day covered by a medical certificate, a customer who had already entered into a payment arrangement, but had broken the arrangement prior to seeking a medical certification, may be required to pay all amounts that were due up to the date of the original medical certificate as a condition of obtaining a new payment arrangement. At no time shall a payment from the customer be required as a condition of honoring a medical certificate.
  - (C) The certificate of medical emergency shall be in writing, sent to the utility from the office of a licensed physician, and show clearly the name of the customer or individual whose illness is at issue; the Colorado medical identification number, phone number, name, and signature of the physician or health care practitioner acting under a physician's authority certifying the medical emergency. Such certification shall be incontestable by the utility as to the medical judgment, although the utility may use reasonable means to verify the authenticity of such certification.

**4408. Notice of Discontinuance.**

- (a) Except as provided in paragraphs (g) and (h) of this rule, a utility shall provide, by first class mail or by hand-delivery, written notice of discontinuance of service at least 15 days in advance of any proposed discontinuance of service. The heading shall contain, in bold font and capital letters, the following warning:
- THIS IS A FINAL NOTICE OF DISCONTINUANCE OF UTILITY SERVICE AND  
CONTAINS IMPORTANT INFORMATION ABOUT YOUR LEGAL RIGHTS AND  
REMEDIES. YOU MUST ACT PROMPTLY TO AVOID UTILITY SHUT OFF.**
- (b) The body of the notice of discontinuance under paragraph (a) of this rule shall at a minimum advise the customer of the following:
- (I) the reason for the discontinuance of service and of the particular terms of service and rule (if any) which has been violated;
  - (II) the amount past due for utility service, deposits, or other regulated charges, if any;

- (III) the date by which an installment payment plan must be entered into or full payment must be received in order to avoid discontinuance of service;
  - (IV) how and where the customer can pay or enter into an installment payment plan prior to the discontinuance of service;
  - (V) that the customer may avoid discontinuance of service by entering into an installment payment plan with the utility pursuant to rule 4404 as described in the utility's applicable tariff;
  - (VI) that the customer has certain rights if the customer or a member of the customer's household is seriously ill or has a medical emergency;
  - (VII) that the customer has the right to dispute the discontinuance directly with the utility by contacting the utility, and how to contact the utility toll-free from within the utility's service area;
  - (VIII) that the customer has the right to make an informal complaint to the Commission in writing, by telephone, or in person, along with the Commission's address and local and toll-free telephone number;
  - (IX) that the customer has the right to file a formal complaint, in writing, with the Commission pursuant to rule 1302 and that this formal complaint process may involve a formal hearing;
  - (X) that in conjunction with the filing of a formal complaint, the customer has a right to file a motion for a Commission order ordering the utility not to disconnect service pending the outcome of the formal complaint process and that the Commission may grant the motion upon such terms as it deems reasonable, including but not limited to the posting of a deposit or bond with the utility or timely payment of all undisputed regulated charges;
  - (XI) that if service is discontinued for non-payment, the customer may be required, as a condition of restoring service, to pay reconnection and collection charges in accordance with the utility's tariff; and
  - (XII) that qualified low-income customers may be able to obtain financial assistance to assist with the payment of the utility bill and that more detailed information on that assistance may be obtained by calling the utility toll-free. The utility shall state its toll-free telephone number.
- (c) At the time it provides notice of discontinuance to the customer, a utility shall also provide written notice by first class mail or hand-delivery to any third-party the customer has designated in writing to receive notices of discontinuance or broken arrangement.
- (d) A discontinuance notice shall be printed in English and a specific language or languages other than English where the utility's service territory contains a population of at least ten percent who speak a specific language other than English as their primary language as determined by the latest U.S. Census information.

- (e) A utility shall explain and shall offer the terms of an installment payment plan to each customer who contacts the utility in response to a notice of discontinuance of service.
- (f) Following the issuance of the notice of discontinuance of service, and at least 24 hours prior to discontinuance of service, a utility shall attempt to give notice of the proposed discontinuance in person or by telephone both to the customer and to any third party the customer has designated in writing to receive such notices. If the utility attempts to notify the customer in person but fails to do so, it shall leave written notice of the attempted contact and its purpose.
- (g) If a customer has entered into an installment payment plan and has defaulted or allowed a new bill to remain unpaid past its due date, a utility shall provide, by first class mail or by hand-delivery, a written notice to the customer. The notice shall contain:
  - (I) a heading as follows: NOTICE OF BROKEN ARRANGEMENT
  - (II) statements that advise the customer:
    - (A) that the utility may discontinue service if it does not receive the monthly installment payment within ten days after the notice is mailed or hand-delivered;
    - (B) that the utility may discontinue service if it does not receive payment for the current bill within 30 days after its due date;
    - (C) that, if service is discontinued, the utility may refuse to restore service until the customer pays all amounts for regulated service more than 30 days past due and any collection or reconnection charges; and
    - (D) that the customer has certain rights if the customer or a member of the customer's household is seriously ill or has a medical emergency.
- (h) A utility is not required to provide notice under this rule if one of the following applies:
  - (I) the situation involves safety concerns;
  - (II) discontinuance is ordered by any appropriate governmental authority;
  - (III) either paragraph 4407(c) or 4407(d) applies; or
  - (IV) service, having been already properly discontinued, has been restored by someone other than the utility and the original cause for discontinuance has not been cured.
- (i) Where a utility knows that the service to be discontinued is used by customers in multi-unit dwellings, in places of business, or in a cluster of dwellings or places of business and the utility service is recorded on a single meter used either directly or indirectly by more than one unit, the utility shall issue notice as required in paragraphs (a) and (b) of this rule, except that:
  - (I) the notice period shall be 30 days;
  - (II) such notice may include the current bill;

- (III) the utility shall provide written notice to each individual unit, stating that a notice of discontinuance has been sent to the party responsible for the payment of utility bills for the unit and that the occupants of the units may avoid discontinuance by paying the next new bill in full within 30 days of its issuance and successive new bills within 30 days of issuance; and
- (IV) the utility shall post the notice in at least one of the common areas of the affected location.

**4409. Restoration of Service.**

- (a) Unless prevented from doing so by safety concerns, a utility shall restore, without additional fee or charge, any discontinued service which was not properly discontinued or restored as provided in rules 4407, 4408, and 4409.
- (b) Unless prevented by safety concerns, a utility shall restore service within 24 hours (excluding weekends and holidays), or within 12 hours if the customer pays any necessary after-hours charges established in tariffs, if the customer does any of the following:
  - (I) pays in full the amount for regulated charges shown on the notice and any deposit and/or fees as may be specifically required by the utility's tariff in the event of discontinuance of service;
  - (II) pays any reconnection and collection charges specifically required by the utility's tariff, enters into an installment payment plan, and makes the first installment payment, unless the cause for discontinuance was the customer's breach of such an arrangement;
  - (III) presents a medical certification, as provided in subparagraph 4407(e)(IV);
  - (IV) demonstrates to the utility that the cause for discontinuance, if other than non-payment, has been cured.

**4410. Refunds.**

- (a) A utility shall file an application for Commission approval of a refund plan if it seeks to refund monies of an amount that exceeds one half of one percent of the utility's prior year's total gross revenues as reported to the Commission in its most recent annual report. The utility may refund amounts to the appropriate customers or classes of customers of less than one half of one percent of the utility's prior year's gross revenues without Commission approval; however, such refunds are required to be noted in the utility's annual report when filed with the Commission pursuant to paragraph 4006(a).
- (b) The application for approval of a refund plan shall include, in the following order and specifically identified, the following information either in the application or in the appropriately identified attachments:
  - (I) all the information required in paragraphs 4002(b) and 4002(c);
  - (II) the reason for the proposed refund;

- (III) a detailed description of the proposed refund plan, including the type of utility service involved, the service area involved, the class(es) of customers to which the refund will be made, and the dollar amount (both the total amount and the amount to be paid to each customer class) of the proposed refund. The interest rate on the refund shall be the current interest rate in the applying utility's customer deposits tariff;
  - (IV) the date the applying utility proposes to start making the refund, which shall be no more than 60 days after the filing of the application; the date by which the refund will be completed; and the means by which the refund is proposed to be made;
  - (V) if applicable, a reference (by proceeding number, decision number, and date) to any Commission decision requiring the refund or, the order itself if the refund is to be made because of receipt of monies by the applying utility under the order of a court or of another state or federal agency;
  - (VI) a statement describing in detail the extent to which the applying utility has any financial interest in any other company involved in the refund plan;
  - (VII) a statement showing accounting entries under the Uniform System of Accounts; and
  - (VIII) a statement that, if the application is granted, the applying utility will file an affidavit verifying that the refund has been made in accordance with the Commission's decision.
- (c) A utility shall pay 90 percent of all undistributed balances, plus associated interest, to the energy assistance organization. For purposes of this rule, a refund is deemed undistributed if, after good faith efforts, a utility is unable to find the person entitled to a refund within the period of time fixed by the Commission in its decision approving the refund plan.
- (d) A utility shall pay an undistributed refund to the energy assistance organization within four months after the refund is deemed undistributed. A utility shall pay interest on an undistributed refund from the time it receives the refund until the refund is paid to the energy assistance organization. The interest rate shall be equal to the interest rate set by the Commission pursuant to paragraph 4403(m).
- (e) Whenever a utility makes a refund, it shall provide written notice to those customers that it believes may be master meter operators. The notice shall contain:
- (I) the definition of master meter operator, as set forth in these rules;
  - (II) a statement regarding a mater meter operator's obligation to do the following:
    - (A) to notify its end users of their right to claim, within 90 days, their proportionate share of the refund; and
    - (B) after 90 days, if the unclaimed balance exceeds \$100, to remit the unclaimed balance to the energy assistance organization.
- (f) A utility shall resolve all inquiries regarding a customer's undistributed refund and shall not refer such inquiries to the energy assistance organization.

- (g) If a utility has paid an undistributed refund to the energy assistance organization, a customer later makes an inquiry claiming that refund, and the utility resolves the inquiry by paying that refund to the customer, the utility may deduct the amount paid to the customer from future funds submitted to the energy assistance organization.

**4411. Low-Income Energy Assistance Act.**

- (a) Scope and applicability.
- (I) Rule 4411 is applicable to gas and combined gas and electric utility providers except those exempted under (II) or (III). Pursuant to §§ 40-8.7-101 through 111, C.R.S., utilities are required to provide an opportunity for their customers to contribute an optional amount through the customers' monthly billing statement.
- (II) Municipally owned gas or gas and electric utilities are exempt if:
- (A) the utility operates an alternative energy assistance program to support its low-income customers with their energy needs and self-certifies to the Organization through written statement that its program meets the following criteria:
- (i) the amount and method for funding of the program has been determined by the governing body; and
- (ii) the program monies will be collected and distributed in a manner and under eligibility criteria determined by the governing body for the purpose of residential energy assistance to customers who are challenged with paying energy bills for financial reasons, including seniors on fixed incomes, individuals with disabilities, and low-income individuals, or,
- (B) the governing body of the utility determines its service area has a limited number of people who qualify for energy assistance and self-certifies to the Organization via written statement such determination.
- (III) A municipally owned gas or gas and electric utility not exempt under subparagraph (a)(II) of this rule, is exempt if:
- (A) the utility designs and implements a procedure to notify all customers at least twice each year of the option to conveniently contribute to the Organization by means of a monthly energy assistance charge. Such procedure shall be approved by the governing utility. The governing body of such utility shall determine the disposition and delivery of the optional energy assistance charge that it collects on the following basis:
- (i) delivering the collections to the organization for distribution; or
- (ii) distributing the moneys under criteria developed by the governing body for the purpose set forth in subparagraph (a)(II)(A)(ii) of this rule;



- (B) alternatively, the utility provides funding for energy assistance to the Organization by using a source of funding other than the optional customer contribution on each customer bill that approximates the amount reasonably expected to be collected from an optional charge on customer's bills.
  - (IV) A municipally gas or gas and electric utility that is exempt under subparagraph (a)(III) of this rule shall be entitled to participate in the Organization's low-income assistance program.
  - (V) Gas or gas and electric utilities that desire a change in status must inform the Organization and file a notice to the Commission within 30 days prior to expected changes.
- (b) Definitions. The following definitions apply only in the context of rule 4411. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.
- (I) "Alternative energy assistance program" means a program operated by a municipally owned electric and gas utility or rural electric cooperative that is not part of the energy assistance program established pursuant to this statute.
  - (II) "Customer" means the named holder of an individually metered account upon which charges for electricity or gas are paid to a utility. "Customer" shall not include a customer that receives electricity or gas for the sole purpose of reselling the electricity or gas to others.
  - (III) "Energy assistance program" or "Program" means the Low Income Energy Assistance Program created by § 40-8.7-104, C.R.S., and designed to provide financial assistance, residential energy efficiency, and energy conservation assistance.
  - (IV) "Organization" means Energy Outreach Colorado, a Colorado nonprofit corporation.
  - (V) "Remittance device" means the section of a customer's utility bill statement that is returned to the utility company for payment. This includes but is not limited to paper payment stubs, web page files used to electronically collect payments, and electronic fund transfers.
  - (VI) "Utility" means a corporation, association, partnership, cooperative electric association, or municipally owned entity that provides retail electric service or retail gas service to customers in Colorado. "Utility" does not mean a propane company.
- (c) Plan implementation and maintenance.
- (I) Except as provided in paragraph 4411(a), each utility shall implement and maintain a customer opt-in contribution mechanism. The utility's opt-in mechanism shall include, at minimum, the following provisions.
    - (A) A description of the procedures the utility will use to notify its customers, including those customers that make payments electronically, about the opt-in provision. Utilities may combine their efforts to notify customers into a single

state-wide or region-wide effort consistent with the participating utilities communication programs. Each participating utility shall clearly identify its support of the combined communications program, with its corporate name and/or logo visible to the intended audience.

- (B) A description of the additional efforts the utility will use to inform its customers about the program to ensure that adequate notice of the opt-in provision is given to all customers. Notification shall include communication to all customers that the donation and related information will be passed through to the Organization.
- (C) A description of the check-off mechanism that will be displayed on the monthly remittance device to solicit voluntary donations. The remittance device shall include, at minimum, check-off categories of five dollars, ten dollars, twenty dollars, and “other amount”. The remittance device must also note the name of the program as the “voluntary energy assistance program,” or if the utility is unable to identify the name of the program individually, the utility shall use a general energy assistance identifier approved by the Commission.
- (D) A description or an example of how the utility will display the voluntary contribution as a separate line item on the customer’s monthly billing statement and how the voluntary contribution will be included in the total amount due. The line item must identify the contribution as “voluntary”.
- (E) A description of the notification process that the utility will use to ensure that once a utility customer opts into the program, the energy assistance contribution will be assessed on a monthly basis until the customer notifies the utility of the customer’s desire to stop contributing. The utility shall describe how it will manage participation in the program when customers miss one or more voluntary payment, or pay less than the pre-selected donation amount.
- (F) Identification of the procedures the utility will use to notify customers of their ability to cancel or discontinue voluntary contributions along with a description of the mechanism the utility will use to allow customers who make electronic payments to discontinue their participation in the opt-in program.
- (G) A description of the procedures the utility will use, where feasible, to notify customers participating in the program about the customer’s ability to continue to contribute when the customer changes their address within the utility’s service territory.
- (H) A description of the method the utility will use to provide clear, periodic, and cost-effective notice of the opt-in provision to its customers at least twice per year. Acceptable methods include, but are not limited to, bill inserts, statements on the bill or envelope, and other utility communication pieces.
- (I) A description of the start-up costs that the utility incurred in connection with the program along with supporting detailed justification for such costs. The description should include the utility’s initial costs of setting up the collection mechanism and reformatting its billing systems to solicit the optional contribution

but shall not include the cost of any notification efforts by the utility. Utilities may elect to recover all start-up costs before the remaining moneys generated by the program are distributed to the Organization or over a period of time from the funds generated by the program, subject to Commission review and approval.

- (J) An estimate of the on-going costs that the utility expects to incur in connection with the program along with supporting detailed justification for such costs. This estimate shall not include the cost of any notification efforts by the utility.
  - (K) A detailed justification for the costs identified in (I) and (J). As stated in § 40-8.7-104(3), C.R.S., the costs incurred must be reasonable in connection with the program.
  - (L) Utilities shall recover the start up cost and on-going cost of administration associated with the program from funds generated from the program. Insert and notification costs shall be considered in the utility's cost of service.
  - (M) A description of the procedures the utility will use to account for and process program donations separately from customer payments for utility services.
- (II) Each utility shall participate in the energy assistance program consistent with its plan approved by the Commission and shall provide the opportunity for its customers to make an optional energy assistance contribution on the monthly remittance device on their utility bill.
  - (III) The utility may submit an application to the Commission no later than April 1 of each year for approval of reimbursement costs the utility incurred for the program during the previous calendar year. Such application shall include a proposed schedule for the reimbursement of these costs to the utility. The applications shall include detailed supporting justification for approval of these costs. Such detailed justification includes, but is not limited to, copies of invoices and time sheets. Such applications shall not seek reimbursement of costs related to notification efforts. Participating utilities may request reimbursement costs for such notification efforts in base rate filings, subject to Commission review and approval.
  - (IV) A utility may seek modification of its initial plan or subsequent plans by filing an application with the Commission.
- (d) Fund administration.
- (I) At a minimum, each utility shall transfer the funds collected from its customers under the energy assistance program to the organization under the following schedule:
    - (A) for the funds collected during the period of January 1 to March 31 of each year, the utility shall transfer the collected funds to the Organization before May 1 of such year;

- (B) for the funds collected during the period of April 1 to June 30 of each year, the utility shall transfer the collected funds to the Organization before August 1 of such year;
  - (C) for the funds collected during the period of July 1 to September 30 of each year, the utility shall transfer the collected funds to the Organization before November 1 of such year;
  - (D) for the funds collected during the period of October 1 to December 31 of each year, the utility shall transfer the collected funds to the Organization before February 1 of the next year; and
  - (E) each utility shall maintain a separate accounting for all energy assistance program funds received by customers.
- (II) Each utility shall provide the organization with the following information.
- (A) How the funds collected for the previous calendar year were generated, including the number of customers participating in the program. Such report shall include a summary of the number of program participants and funds collected by month, and shall be provided by February 1 of each year.
  - (B) At each time funds are remitted, a listing of all program participants including the donor's name, billing address, and monthly donation amount. The participant information provided to the organization shall be used exclusively for complying with the requirements of § 40-8.7-101, C.R.S., et seq. and state and federal laws.
- (III) The Public Utilities Commission shall submit, as necessary, a bill for payment to the Organization for any administrative costs incurred pursuant to the program.
- (IV) The organization shall provide the Office of Consumer Counsel and the Public Utilities Commission with a copy of the written report that is described in § 40-8.7-110, C.R.S. This report shall not contain individual participant information.
- (e) Prohibition of disconnection. Utilities shall not disconnect a customer's gas service for non-payment of optional contribution amounts.

**4412. Gas Service Low-Income Program.**

- (a) Scope and applicability.
  - (I) Gas utilities with Colorado retail customers shall provide low-income energy assistance by offering rates, charges, and services that grant a reasonable preference or advantage to residential low-income customers, as permitted by § 40-3-106, C.R.S.
  - (II) Rule 4412 is applicable to investor-owned gas utilities subject to rate regulation by the Commission.

- (b) Definitions. The following definitions apply only in the context of rule 4412. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.
- (I) “Administrative cost” means the utility’s direct cost for labor (to include the cost of benefit loadings), materials, and other verifiable expenditures directly related to the administration and operation of the program not to exceed ten percent of the total cost of program credits applied against bills for current usage and pre-existing arrearages or \$10,000, whichever amount is greater.
  - (II) “Affordable percentage of income payment” means the amount of the participant’s annual bill deemed affordable under subparagraph 4412(e)(I).
  - (III) “Arrearage” means the past-due amount appearing, as of the date on which a participant newly enters the program, on the then most recent prior bill rendered to a participant for which they received the benefit of service.
  - (IV) “Colorado Energy Office” (CEO) means the Colorado Energy Office created in § 24-38.5-101, C.R.S.
  - (V) “Eligible low-income customer” means a residential utility customer who meets the household income thresholds pursuant to paragraph 4412(c).
  - (VI) “Fixed credit” means an annual bill credit established at the beginning of a participant’s participation in a program each year delivered as a monthly credit on each participant’s bill. The fixed credit is the participant’s full annual bill minus the participant’s affordable percentage of income payment obligation on the full annual bill.
  - (VII) “Full annual bill” means the current consumption of a participant billed at standard residential rates. The full annual bill of a participant is comprised of two parts: (1) that portion of the bill that is equal to the affordable percentage of income payment; and (2) that portion of the bill that exceeds the affordable percentage of income payment.
  - (VIII) “LEAP” means Low-Income Energy Assistance Program, a county-run, federally-funded, program supervised by the Colorado Department of Human Services, Division of Low-Income Energy Assistance.
  - (IX) “LEAP participant” means a utility customer who at the time of applying to participate in a program has been determined to be eligible for LEAP benefits by the Department during either the Department’s current six-month (November 1 – April 30) LEAP application period, if that period is open at the time the customer applies for program participation; or (the Department’s most recently closed six-month (November 1 – April 30) LEAP application period, if that period is closed at the time the customer applies to participate in the program and the Department’s next six-month (November 1 – April 30) LEAP application period has not yet opened, provided, however, that in order to retain status as a LEAP participant under this definition, the utility customer must apply to the Department during the Department’s next six-month (November 1 – April 30) LEAP benefit application period and be determined eligible for such benefits.

- (X) “Non-participant” means a utility customer who is not receiving low-income assistance under rule 4412.
  - (XI) “Participant” means an eligible low-income residential utility customer who is granted the reasonable preference or advantage through participation in a gas service low-income program.
  - (XII) “Percentage of Income Payment Plan” (PIPP) means a payment plan for participants that does not exceed an affordable percentage of their household income as set forth in subparagraph 4412(e)(I).
  - (XIII) “Program” means a gas service low-income program approved under rule 4412.
  - (XIV) “Program credits” means the amount of benefits provided to participants to offset the unaffordable portion of a participant’s utility bill and /or dollar amounts credited to participants for arrearage forgiveness.
  - (XV) “Unaffordable portion” means the amount of the estimated full annual bill that exceeds the affordable percentage of income payment.
- (c) Participant eligibility. Eligible participants are limited to those with a household income at or below 185 percent of the current federal poverty level, or, if the utility applies individual LEAP benefits to offset the costs of the unaffordable portion of the participating customer’s utility bill, the percent of the current federal poverty level set by the Colorado Department of Human Services, Division of Low-income Energy Assistance for eligibility in the LEAP program.
- (I) Gas utilities may obtain federal annual poverty level income amounts based on household size on the Colorado Department of Human Services, Division of Low Income Energy Assistance website at <https://sites.google.com/a/state.co.us/cdhs-leap/program-eligibility>.
  - (II) The utility shall obtain household income information from LEAP.
  - (III) If a participant’s household income is \$0, the utility may establish a process that verifies income on a more frequent basis.
  - (IV) Program participants shall not be required to make payment on their utility account as a condition of entering into the program.
- (d) Enrollment. Utilities shall be responsible for the methods by which participant enrollment in their approved low income program is obtained and sustained, however the utility should engage in enrollment processes that are efficient and attempt to maximize the potential benefits of participation in the low income program by low income customers.

- (e) Payment plan.
- (I) Participant payments for natural gas bills rendered to participants shall not exceed an affordable percentage of income payment. For accounts for which natural gas is the primary heating fuel, participant payments shall be no lower than two percent and not greater than three percent of the participant's household income.
  - (II) In the event that a primary heating fuel for any particular participant has been identified by LEAP, that determination shall be final.
  - (III) Notwithstanding the percentage of income limits established in subparagraph 4412(e)(I), a utility may establish minimum monthly payment amounts for participants with household income of \$0, provided that the participant's minimum payment for a natural gas account shall be no more than \$10.00 a month.
  - (IV) Full annual bill calculation. The utility shall be responsible for estimating a participant's full annual bill for the purpose of determining the unaffordable portion of the participant's full annual bill delivered as a fixed credit on the participant's monthly billing statement.
  - (V) Fixed credit benefit. The fixed credit shall be adjusted during a program year in the event that standard residential rates, including commodity or fuel charges change to the extent that the full annual bill at the new rates would differ from the full annual bill upon which the fixed credits are currently based by 25 percent or more.
  - (VI) Levelized budget billing participation. A utility shall enroll participants in its levelized budget billing program as a condition of participation in the program. Should a participant fail to meet monthly bill obligations and be placed by a utility in its regular delinquent collection cycle, the utility may remove the participant from levelized budget billing in accordance with the utility's levelized budget billing tariff.
  - (VII) Arrearage credits.
    - (A) Arrearage credits shall be applied to pre-existing arrearages.
    - (B) Arrearage credits shall be sufficient to reduce, when combined with participant copayments, if any, the pre-existing arrearages to \$0.00 over a period not less than one month and not more than twenty-four months.
    - (C) Application of an arrearage credit to a participant account may be conditioned by the utility on one or more of the following:
      - (i) the receipt of regular participant payments toward bills for current usage;  
or
      - (ii) the payment of a participant copayment toward the arrearages so long as the participant's copayment total dollar amount does not exceed one percent of gross household income.

- (D) Should the participant exit the program prior to the full forgiveness of all pre-existing arrearages, the amount of remaining pre-existing arrearages shall become due in accordance with the utilities tariff filed under rules 4401, 4407, and 4408.
  - (E) Pre-existing arrears under this subparagraph shall not serve as the basis for the termination of service for nonpayment or as the basis for any other utility collection activity while the customer is participating in the program.
  - (F) A participant may receive arrearage credits under this section even if that participant does not receive a credit toward current bills, if the participant enters into and maintains a levelized budget billing plan.
- (VIII) Portability of benefits. A participant may continue to participate without reapplication should the participant change service addresses, but remain within the service territory of the utility providing the benefit, provided that the utility may make necessary adjustments in the levelized budget billing amount to reflect the changed circumstances. A participant who changes service addresses and does not remain within the service territory of the utility providing the benefit must reapply to become a participant at the participant's new service address.
- (IX) Payment default provisions. Failure of a participant to make his or her monthly bill payments will result in a utility placing the participant in its regular collection cycle. Missed, partial or late payments shall not result in the removal of a participant from the program.
- (f) Program implementation.
- Each utility shall maintain effective terms and conditions in its tariffs on file with the Commission describing its low-income program.
- (g) Cost recovery.
- (I) Each utility shall include in its low income tariff terms and conditions how costs of the program will be recovered.
  - (II) Program cost recovery.
    - (A) Program cost recovery shall be based on a fixed monthly fee.
    - (B) The maximum impact on residential rates shall be no more than \$00.31 per month.
    - (C) In order to determine monthly rates applicable to rate classes other than residential, program costs shall be allocated to each retail rate based on each rate class's share of the test year revenue requirement established in the utility's last Phase II rate case, or under another reasonable methodology supported by quantifiable information. The monthly rate per this subparagraph to be charged each rate schedule customer shall be clearly stated on a tariff sheet.



- (D) Utilities shall separately account for the cumulative program cost recovery and cumulative program and administrative costs to determine if the net of program cost recovery and program and administrative cost are in balance during the program year.
  - (i) Beginning October 31, 2018 and in each year thereafter, the utility shall file a report with the Commission in the most recent miscellaneous proceeding for annual low-income filings detailing the net difference between program cost recovery and program costs as of September 30 of each year.
    - (1) Should the net difference of program cost recovery over program costs be greater than 50 percent derived in (ii) above, either positive or negative, and the utility is not currently at the maximum impact for non-participants, the utility shall file with the Commission an advice letter and tariff pages seeking approval for the rates determined in subparagraph 4412(g)(II)(D) in order to bring the projected recovery in balance for the ensuing 12 month period. The revised Residential charge shall not exceed the maximum impact for non-participants in subparagraph 4412(g)(II)(C).
- (III) The following costs are eligible for recovery by a utility as program costs:
  - (A) program credits or discounts applied against bills for current usage;
  - (B) program credits applied against pre-existing arrearages;
  - (C) program administrative costs; and
  - (D) Commission-sponsored program evaluation costs required under paragraph 4412(k).
- (IV) The utility shall apply, as an offset to cost recovery, all program expenses attributable to the program. Program expenses include utility operating costs; changes in the return requirement on cash working capital for carrying arrearages; changes in the cost of credit and collection activities directly related to low-income participants; and changes in uncollectable account costs for these participants.
- (V) LEAP grants.
  - (A) The utility shall apply energy assistance grants provided to the participant by the LEAP program to the dollar value of credits granted to individual program participants.
  - (B) A utility shall apply any energy assistance benefit granted to the participant by LEAP to that portion of the program participant's full annual bill that exceeds the participant's affordable percentage of income payment.

- (C) If the dollar value of the energy assistance grant is greater than the dollar value of the difference between the program participant's full annual bill and the participant's affordable percentage of income payment, the dollar amount by which the energy assistance grant exceeds the difference will be applied:
    - (i) first, to any pre-existing arrearages that at the time of the energy assistance grant continues to be outstanding; and
    - (ii) second, to the account of the program participant as a benefit to the participant.
  - (D) No portion of an energy assistance or LEAP grant provided to a program participant may be applied to the account of a participant other than the participant to whom the energy assistance grant was rendered.
- (h) Other programs. In addition to the utility's low-income program, with Commission approval, a utility may offer other rate relief options to eligible households.
- (I) Other programs offered by the utility under rule 4412 must be intended to reach low-income households that do not substantially benefit from the provisions of the low-income program. Such programs may take the form of discount rates, tiered discount rates or other direct bill relief methods where the low-income household benefitting from the program is granted a reasonable preference in tariffed rates assessed to all residential utility customers.
  - (II) Cost recovery for other programs combined with the Percentage of Income Payment Plan shall not exceed the maximum impact on residential rates described in subparagraph 4412(g)(II)(C).
- (i) Energy efficiency and weatherization.
- (I) The utility shall provide all program participants with information on energy efficiency programs offered by the utility or other entities and existing weatherization programs offered by the state of Colorado or other entities.
  - (II) The utility shall provide the Colorado Energy Office with the name and service address of participant households for which annual natural gas usage exceeds 600 therms annually.
- (j) Stakeholder engagement. A utility shall conduct annual meetings with low-income stakeholders for the purpose of seeking solutions to issues of mutual concern and aligning program practices with the needs of customers and other stakeholders.
- (k) Program evaluation. A triennial evaluation of the program provisions under rule 4412 beginning in 2019 shall be undertaken in order to review best practices in similar low income assistance programs in existence in other regulatory jurisdictions, as well as evaluate operation of each utility's program for effectiveness in achieving optimum support being provided to low income participants. The evaluation shall also recommend modifications if available that improve the delivery of benefits to participants and increase the efficiency and effectiveness of each program as they exist at the point of evaluation.

- (I) Procurement of the third-party vendor that will perform the evaluation will be undertaken by the Colorado Energy Office. The CEO shall seek the involvement of interested stakeholders including, but not limited to, Commission staff, all Commission regulated electric and gas utilities, LEAP, the Office of Consumer Counsel, and Energy Outreach Colorado in the design of the requirements regarding study focus and final reporting.
  - (II) Approval of the third-party vendor shall be the responsibility of the Commission. The CEO shall file with the Commission in the most recent annual report proceeding, a request for approval of the contract of the vendor selected. The Commission shall review and act on the request within 30 days.
  - (III) \$00.0013 per customer per month shall be set aside by the utility starting in the 2016-2017 program year in order to cover the cost of the program evaluation described in paragraph 4412(k).
  - (IV) The dollars resulting from the \$00.0013 charge shall be recovered as a program cost under subparagraph 4412(g)(III).
  - (V) The evaluation will be filed by Commission staff in the most recent miscellaneous proceeding for annual low income filings.
  - (VI) Staff and the CEO will assess the individual utilities' deferred balances set aside for the program evaluation starting in 2019 at the conclusion of the third program year and each three years thereafter and will determine the amounts each utility is to remit to the third party evaluator based on the contractual terms approved by the Commission for the evaluation.
- (I) Annual report. No later than December 31, of each year the utility shall file a report in the most recent miscellaneous proceeding established by the Commission to receive annual low income filings using the form available on the Commission's website, based on the 12-month period ending October 31 containing the following information:
- (I) monthly information on the program including number of participants, amount of benefit disbursement, type of benefit disbursement, LEAP benefits applied to the unaffordable portion of participant's bills, administrative costs, and revenue collection;
  - (II) the number of applicants for the program;
  - (III) the number of applicants qualified for the program;
  - (IV) the number of participants;
  - (V) the average assistance provided, both mean and median;
  - (VI) the maximum assistance provided to an individual participant;
  - (VII) the minimum assistance provided to an individual participant;

- (VIII) total cost of the program and the average rate impact on non-participants by rate class, including impact based on typical monthly consumption of both its residential and small business customers;
- (IX) the number of participants that had service discontinued as a result of late payment or non-payment, and the amount of uncollectable revenue from participants;
- (X) an estimate of utility savings as a result of the implementation of the program (e.g., reduction in trips related to discontinuance of service, reduction in uncollectable revenue, etc.);
- (XI) the average monthly and annual total natural gas consumption in PIPP participants' homes;
- (XII) the average monthly and annual total natural gas consumption in the utility's residential customer's homes;
- (XIII) the number of program participants referred to the weatherization program;
- (XIV) a description of the ways in which the program is being integrated with existing energy efficiency of DSM programs offered by the utility;
- (XV) a description of the ways in which the program is being integrated with existing weatherization programs offered by the state of Colorado;
- (XVI) a description of program outreach strategies and metrics that illustrate the effectiveness of each outreach strategy;
- (XVII) the number of participants at the start of the program year that the utility removed for any reason, the number of potential participants rejected because of the existence of a cap on the program, the period of arrearage time from date participants became eligible and were granted arrearage forgiveness, and the number of participants who came back as eligible participants in the program year after being eligible in a prior program year and were provided arrearage credits in the program year; and
- (XVIII) a narrative summary of the utility's recommended program modifications based on report findings.

**4413. – 4499. [Reserved].**

## **UNREGULATED GOODS AND SERVICES**

### **4500. Overview and Purpose.**

The purpose of these rules is to establish cost assignment and allocation principles to assist the Commission in setting just and reasonable rates and to ensure that utilities do not use ratepayer funds to subsidize non-regulated activities, in accordance with § 40-3-114, C.R.S. In order to promote these purposes, these rules also specify information that utilities must provide to the Commission. In providing for review of a utility's specific cost allocations in other states and jurisdictions, the rules merely

contemplate a methodology to allow interested parties to obtain complete information regarding cost allocations. These rules do not expressly or implicitly allow this Commission to order a utility to revise its cost allocations in other jurisdictions or states.

#### **4501. Definitions.**

The following special definitions apply only to rules 4501 through 4505. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- (a) “Activity” means a business activity, product or service whether offered by a Colorado utility, a division of a Colorado utility, or an affiliate of a Colorado utility.
- (b) “Allocate” or “Allocated” or “Cost Allocation” means to distribute a joint or common cost to or from more than one activity or jurisdiction.
- (c) “Assigned Costs” or “Cost Assignment” means a cost that is specifically identified with a particular activity or jurisdiction and charged directly to that activity or jurisdiction. At no point in the process of making the cost assignment is an allocation applied.
- (d) “Cost Assignment and Allocation Manual” (CAAM) means the indexed document filed by a utility with the Commission that describes and explains the cost assignment and allocation methods the utility uses to segregate and account for revenues, expenses, assets, liabilities, and rate base cost components assigned or allocated to Colorado jurisdictional activities. It includes the cost assignment and allocation methods to segregate and account for costs between and among jurisdictions, between regulated and non-regulated activities, and between and among utility divisions.
- (e) “Division” means an activity conducted by a Colorado utility but not through a legal entity separate from the Colorado utility. It includes the electric, gas, or thermal activities of a Colorado utility and any non-regulated activities provided by the Colorado utility.
- (f) “Fully Distributed Cost” (FDC) means the process of segregating, assigning, and allocating the revenues, expenses, assets, liabilities and rate base amounts recorded in the utility’s accounting books and records using cost accounting, engineering, and economic concepts, methods and standards. Fully distributed cost includes a return on investment in cases where assets are used.
- (g) “Fully Distributed Cost Study” is a cost study that reflects the result of the fully distributed revenues, expenses, assets, liabilities and rate base amounts for the Colorado utility to and from the different activities, jurisdictions, divisions, and affiliates using cost accounting, engineering, and economic concepts, methods, and standards.
- (h) “Incidental Services” means non-tariff or non-regulated services that have traditionally been offered incidentally to the provisions of tariff services where the revenues for all such services do not exceed:
  - (l) The greater of \$100,000 or one percent of the provider’s total annual Colorado operating revenues for regulated services; or,

- (II) Such amount established by the Commission considering the nature and frequency of the particular service.
- (i) “Jurisdictional” means having regulatory rate authority over a utility. Jurisdiction can be at a state or federal level.
- (j) “Regulated activity” means any activity that is offered as a public utility service as defined in Title 40, Articles 1 to 7 C.R.S., and is regulated by the Commission or regulated by another state utility commission or the FERC, or any non-regulated activity which meets the criteria specified in rules 4502(g).
- (k) “Non-regulated activity” means any activity that is not offered as a public utility service as defined in Title 40, Articles 1 to 7, C.R.S., and is not regulated by this Commission or another state utility commission or the FERC.
- (l) “Transaction” means the activity that results in the provision of products, services, or assets by one division or an affiliate to another division or an affiliate.

**4502. Cost Assignment and Allocation Principles.**

In determining fully distributed cost, the utility shall apply the following principles (listed in descending order of required application in paragraphs 4502 (a), (b) and (c) below).

- (a) Tariff services provided to an activity will be charged to the activity at the tariff rates.
- (b) If only one activity or jurisdiction causes a cost to be incurred, that cost shall be directly assigned to that activity or jurisdiction.
- (c) Costs that cannot be directly assigned to either regulated or non-regulated activities or jurisdictions will be described as common costs. Common costs shall be grouped into homogeneous cost categories designed to facilitate the proper allocation of costs between regulated and non-regulated activities or jurisdictions. Each cost category shall be fairly and equitably allocated between regulated and non-regulated activities or jurisdictions in accordance with the following principles.
  - (I) Cost causation. All activities or jurisdictions that cause a cost to be incurred shall be allocated a portion of that cost. Direct assignment of a cost is preferred to the extent that the cost can easily be traced to the specific activity or jurisdiction.
  - (II) Variability. If the fully distributed cost study indicates a direct correlation exists between a change in the incurrence of a cost and cost causation, that cost shall be allocated based upon that relationship.
  - (III) Traceability. A cost may be allocated using a measure that has a logical or observable correlation to all the activities or jurisdictions that cause the cost to be incurred.
  - (IV) Benefit. All activities or jurisdictions that benefit from a cost shall be allocated a portion of that cost.

- (V) Residual. The residual of costs left after either direct or indirect assignment or allocation shall be allocated based upon an appropriate general allocator to be defined in the utility's CAAM.
- (d) For cost assignment and allocation purposes, the value of all transactions from the Colorado utility to a non-regulated activity shall be determined as follows:
- (I) if the transaction involves a product or service provided by the utility pursuant to tariff, the value of the transaction shall be at the tariff rate;
  - (II) if the transaction involves a product or service that is not provided pursuant to a tariff, the value of the transaction shall be the higher of the utility's fully distributed cost or market price. Market price shall be either the price charged by the utility, or if this condition cannot be met, the lowest price charged by another person for a comparable product or service; or
  - (III) if the transaction involves the sale of an asset, the value of the transaction shall be the higher of net-book cost or market price. If the transaction involves the use of an asset, the value of the transaction shall be the higher of fully distributed cost or market price. Market price shall be either the price charged by the utility or if this condition cannot be met, the lowest price charged by another person in the market for the sale or use of a comparable asset, when such prices are publicly available.
- (e) For cost assignment and allocation purposes, the value of all transactions from a non-regulated activity to the utility shall be determined as follows:
- (I) if the transaction involves a product or service that is not provided pursuant to a tariff, the value of the transaction shall be the lower of the fully distributed cost or the market price except if the transaction results from a competitive solicitation process then the value of the transaction shall be the winning bid price. Fully distributed cost in this circumstance, shall be the cost that would be incurred by the utility to provide the service internally. Market price shall be either the price charged by the supplying non-regulated activity or if that condition is not met, the lowest price charged by other persons in the market for a comparable product or service, when such prices are publicly available; or
  - (II) if the transaction involves the sale of an asset, the value of the transaction shall be the lower of net-book cost or market price. If the transaction involves the use of an asset, the value of the transaction shall be at the lower of fully distributed cost or market price. Market price shall be either the price charged by the non-regulated activity or, if this condition cannot be met, the lowest price charged by another person in the market for the sale or use of a comparable asset, where such prices are publicly available.
- (f) If it is impracticable for the utility to establish a market price pursuant to paragraphs (d) or (e), the utility shall provide a statement to that effect, including its reasons in its' fully distributed cost study as well as its proposed method and amount for valuing the transaction. Parties in a Commission proceeding retain the right to advocate alternative market prices pursuant to paragraphs (d) and (e).

- (g) A utility may classify non-jurisdictional services as regulated if the services are rate-regulated by another agency (i.e., another state utility commission or the FERC) and where there are agency-accepted principles or methods for the development of rates associated with such services. This rule may apply, for example, to a provider's wholesale sales of electric power and energy. For such services, the utility shall identify the services in its manual, and account for the revenues, expenses, assets, liabilities, and rate base associated with these services as if these services are regulated.
- (h) For cost assignment and allocation purposes, the value of all transactions between regulated divisions within a utility shall be determined as follows:
  - (I) if the transaction involves a service provided by the utility pursuant to tariff, the value of the transaction shall be at the tariff rate, or
  - (II) if the transaction involves a service or function that is not provided pursuant to a tariff, the value of the transaction shall be at cost.
- (i) If the utility offers a service that is a combination of regulated and non-regulated activities (i.e., a bundled service), the utility shall assign and/or allocate costs to the regulated and non-regulated activities separately.
- (j) A utility may classify incidental activities as regulated activities. If an incidental activity is classified as a regulated activity, the utility shall clearly identify the activity as an incidental activity, and account for the revenues, expenses, assets, liabilities and rate base items as if that activity were a regulated activity.
- (k) To the extent possible, all assigned and allocated costs between regulated and non-regulated activities should have an audit trail which is traceable on the books and records of the applicable regulated utility to the applicable accounts pursuant to the Federal Energy Regulatory Commission Uniform System of Accounts.
- (l) In a rate proceeding involving the calculation of revenue requirements, a complaint proceeding where cost assignments or allocations are at issue, or a proceeding where CAAM approval is sought, the utility or any party may advocate a cost allocation principle other than that already in use, if the Commission has already approved the principle for that cost. The party requesting the alternative approach shall have the burden of proving the need for an alternative principle and why the particular principle is appropriate for the particular cost.

**4503. Cost Assignment and Allocation Manuals.**

- (a) Each utility shall maintain on file with the Commission an approved indexed cost assignment and allocation manual which describes and explains the calculation methods the utility uses to segregate and account for revenues, expenses, assets, liabilities, and rate base cost components assigned or allocated to Colorado jurisdictional activities. It includes the calculation methods to segregate and account for costs between and among jurisdictions, between regulated and non-regulated activities, and between and among utility divisions.
- (b) Each utility shall include the following information in its CAAM.



- (I) A listing of all regulated or non-regulated divisions of the Colorado utility together with an identification of the regulated or non-regulated activities conducted by each.
  - (II) A listing of all regulated or non-regulated affiliates of the Colorado utility together with an identification of which affiliates allocate or assign costs to and from the Colorado utility.
  - (III) A listing and description of each regulated and non-regulated activity offered by the Colorado utility. The Colorado utility shall provide a description in sufficient detail to identify the types of costs associated with the activity and shall identify how the activity is offered to the public and identify whether the Colorado utility provides the activity in more than one state. If an activity is offered subject to tariff, the Colorado utility may identify the tariff and the tariff section that describes the service offering in lieu of providing a service description.
  - (IV) A listing of the revenues, expenses, assets, liabilities and rate base items by Uniform System of Accounts account number that the utility proposes to include in its revenue requirement for Colorado jurisdictional activities including those items that are partially allocated to Colorado as well as those items that are exclusively assigned to Colorado.
  - (V) A detailed description showing how the revenues, expenses, assets, liabilities and rate base items by account and sub-account are assigned and/or allocated to the Colorado utility's non-regulated activities, along with a description of the methods used to perform the assignment and allocations.
  - (VI) A description of each transaction between the Colorado utility and a non-regulated activity which occurred since the Colorado utility's prior CAAM was filed and, for each transaction, a statement as to whether, for this Commission's jurisdictional cost assignment and allocation purposes, the value of the transactions is at cost or market as applicable.
  - (VII) A description of the basis for how the assignment or allocation is made.
  - (VIII) If the utility believes that specific cost assignments or allocations are under the jurisdiction of another authority, the utility shall so state in its CAAM and give a written description of the prescribed methods. Nothing herein shall be construed to be a delegation of this Commission's ratemaking authority related to those assignments or allocations.
  - (IX) Any additional information specifically required by Commission order.
- (c) A utility may treat certain transactions as confidential pursuant to the Commission rules on confidentiality.
  - (d) Following the initial approval of its CAAM, the utility shall file an updated CAAM in each rate case proceeding where revenue requirements are determined or every five years following approval of the CAAM then in effect, whichever is earlier.
  - (e) The utility may, at its discretion, file an application seeking Commission approval of updates to its CAAM at any time.

- (f) Whenever a utility files for approval of an update to its CAAM as a result of paragraph (d) or (e) above, the utility shall also simultaneously file a FDC study reflecting the results of the cost allocation methods in its updated manual.
- (g) Each utility shall maintain all records and supporting documentation concerning its CAAMs for so long as such manual is in effect or are subject to a complaint or any active proceeding involving cost allocation before the Commission for as long as such proceeding may be open.

**4504. Fully Distributed Cost Study.**

- (a) The utility shall submit its fully distributed cost study in both electronic and paper format simultaneously with filing its CAAM for all Colorado divisions and activities.
- (b) The utility shall prepare a FDC study that identifies all the non-regulated activities provided by each division in Colorado. The FDC study shall show the revenues, expenses assets, liabilities and rate base items assigned and allocated to each non-regulated activity. If the utility has more than one division (e.g., gas, electric, thermal or non-utility) in Colorado, the FDC study shall include a summary of all assigned and allocated costs by division.
- (c) In preparation of its FDC study, the utility shall complete an analysis of each non-regulated activity to identify the costs that are associated with and/or should be charged to each non-regulated activity to ensure each non-regulated activity is assigned and allocated the appropriate amount of revenues, expenses, assets, liabilities and rate base items.
- (d) If the CAAM is filed in connection with a rate case, the FDC study shall be based on the same test year used in the utility's rate case filing. The utility's FDC study shall include revenues, expenses, assets, liabilities and rate base items in order for the Commission to determine if all appropriate revenues, expenses, assets, liabilities and rate base items have been appropriately assigned and allocated, and to determine the utility's compliance with the principles established in rule 4502. For each assignment and allocation the utility shall:
  - (I) identify the revenues, expenses, assets, liabilities and rate base items by account number, sub-account number and account description; and
  - (II) for each account in (I) above, identify the assignment and allocation method used to assign and allocate costs in sufficient detail to verify the assignment and allocation method used to assign and allocate costs to Colorado divisions and activities is accurate and consistent with the utility's CAAM methodology and reference the CAAM section that describes the allocation; and
  - (III) provide the test year dollar itemized amounts of revenues, expenses, assets, liabilities, and rate base assigned and allocated to each Colorado division and non-regulated activity; the itemized amounts assigned and allocated to the Colorado utility for regulated activities; the itemized amounts assigned and allocated to the Colorado utility for Colorado non-regulated activities; and the itemized amounts assigned and allocated to other jurisdictions.

- (e) Each utility shall maintain all records and supporting documentation concerning its FDC study for so long as such study is in effect or are subject to a complaint or a proceeding before the Commission.

#### **4505. Disclosure of Non-regulated Goods and Services.**

Whenever a Colorado utility engages in the provision or marketing of non-regulated goods or services in Colorado that are not subject to Commission regulation, and the Colorado utility's name or logo is used in connection with the provision of such non-regulated goods and services in Colorado, there must be conspicuous, clear, and concise disclosure to prospective customers that such non-regulated goods and services are not regulated by the Commission. Such disclosure to prospective customers in Colorado shall be included in all Colorado advertising or marketing materials, proposals, contracts, and bills for non-regulated goods and services, regardless of whether the Colorado utility provides such non-regulated goods or services in Colorado directly or through a division or affiliate.

#### **4506. – 4599. [Reserved].**

### **GAS COST ADJUSTMENT AND PRUDENCE REVIEW**

#### **4600. Overview and Purpose.**

Rules 4601 through 4609 are used by LDCs to revise gas rates on an expedited basis. These rules provide instructions for the filing of: gas cost adjustment applications; annual gas purchase plan submittals; and annual gas purchase reports. The purpose of the Gas Cost Adjustment is to enable LDCs, on an expedited basis, to reflect in their rates for gas sales and gas transportation services, as applicable, the increases or decreases in gas costs, including (but not limited to) gas commodity costs and upstream services costs. The purpose of the Gas Purchase Plan is to describe the LDC's plan for purchases of gas commodity and upstream services in order to meet the forecasted demand for sales gas service during each month of the gas purchase year. The purpose of the Gas Purchase Report is to present the LDC's actual purchases of gas commodity and upstream services during each month of the gas purchase year.

#### **4601. Definitions.**

The following definitions apply to rules 4600 through 4609 unless a specific statute or rule provides otherwise. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- (a) "Account No. 191" means an account under the Federal Energy Regulatory Commission System of Accounts used to accumulate actual under-or-over recovered gas supply costs.
- (b) "Base gas cost" means a rate component which is expressed in at least the accuracy of one mil (\$0.001) per Mcf or Dth which reflects the cost of gas commodity and upstream services, when applicable, included in the utility's base rates for sales gas and gas transportation service.
- (c) "Base rates" means the utility's currently-effective rates for sales gas and gas transportation service as authorized by the Commission in the utility's last general rate case.

- (d) "Current gas cost" means a rate component of the GCA which is expressed in at least the accuracy of one mil (\$0.001) per Mcf or Dth and which reflects the cost of gas commodity and upstream service projected to be incurred by the utility during the GCA effective period.
- (e) "Deferred gas cost" means a rate component of the GCA which is expressed in at least the accuracy of one mil (\$0.001) per Mcf or Dth and which is designed to amortize over the GCA effective period the under- or over-recovered gas costs reflected in the utility's Account No. 191 or other appropriate costs for a defined period such as a gas purchase year.
- (f) "Forecasted design peak day quantity" means the total quantity of gas commodity anticipated to be required to meet firm sales and firm gas transportation service demand on the utility's system on a design or historical peak day.
- (g) "Forecasted gas commodity cost" means the cost of gas commodity, including appropriate adjustments for storage gas injections and withdrawals and for exchange gas imbalances, which is projected to be incurred by the utility during the GCA effective period and which is determined by using forecasted gas purchase quantity and forecasted purchase prices.
- (h) "Forecasted gas purchase quantity" means the quantity of gas commodity the utility anticipates it will purchase during the GCA effective period, based upon the forecasted sales gas quantity, adjusted for system gas loss, use, or other anticipated variances.
- (i) "Forecasted purchase prices" means index prices, fixed prices, or other gas contracting price options used in the calculation of the forecasted gas commodity cost.
- (j) "Forecasted sales gas quantity" means the quantity of gas commodity projected to be sold by the utility during the GCA effective period, based upon the normalized quantity of gas commodity sales, adjusted for anticipated changes.
- (k) "Forecasted upstream service cost" means the total cost of upstream services projected to be incurred by the utility during the GCA effective period.
- (l) "Gas commodity throughput" means the amount of gas commodity flowing through the utility's jurisdictional gas facilities during a defined period of time.
- (m) "Gas cost adjustment" or "GCA" means the tariff mechanism by which a gas rate is adjusted to reflect increases or decreases in gas costs.
- (n) "GCA effective period" means the period of time that the GCA rate change is intended to be in effect before being superseded on the effective date of the next scheduled GCA.
- (o) "Gas purchase plan" (GPP) means a submittal pursuant to rule 4605 that describes the utility's planned purchases of gas commodity and upstream services to be used to meet sales gas demand during the gas purchase year.
- (p) "Gas purchase report" (GPR) means a report pursuant to rule 4607 which is filed with the Commission and which describes the utility's actual purchases of gas commodity and upstream services in order to meet sales gas demand during the gas purchase year.

- (q) "Gas purchase year" means a 12-month period from July 1 through June 30.
- (r) "Gas transportation service" means the delivery of gas commodity on the utility's pipeline system (either transmission or distribution) pursuant to any of the utility's gas transportation rate schedules on file with the Commission.
- (s) "Index price" means a published figure identifying a representative price of natural gas commodity available in a geographic area or at specific gas purchasing points during a specified time interval (i.e., daily, weekly, or monthly).
- (t) "Mil" means one-tenth of one cent (\$0.001).
- (u) "Normalized" means the process of adjusting gas quantities to reflect normal historic temperature based on National Oceanic and Atmospheric Administration data or other data as appropriate.
- (v) "Peak day" means a defined period (such as a 24 hour period or a three consecutive coincidental or non-coincidental day average), not less than 24 hours, during which gas commodity throughput is at its maximum level on the utility's system.
- (w) "Receipt point/area" means the point or group of points in a discrete geographic area, such as a supply basin, hub, or market area, at which the utility acquires title to the gas commodity purchased.
- (x) "Sales gas service" means the regulated sale of gas commodity by the utility to customers on the utility's jurisdictional gas system.
- (y) "Service level" means the type or level (whether base, swing, or peak) of gas supply service contracted for by the utility based upon the respective obligations of the supplier to deliver and sell, and the utility to take and purchase, gas commodity.
- (z) "Upstream services" means all transmission, gathering, compression, balancing, treating, processing, storage, and like services performed by others under contract with the utility for the purpose of effectuating delivery of gas commodity to the utility's jurisdictional gas facilities.

**4602. Schedule for Filings by Utilities.**

Utilities subject to rules 4600 through 4609 shall make the required filings in accordance with the following schedule:

- (a) October 1 filing schedule. Public Service Company of Colorado, and Atmos Energy Corporation, shall file with the Commission annual GCA applications with an effective date of October 1. Additional GCA applications may also be filed as necessary pursuant to paragraph 4603(c). The GPR for the preceding gas purchase year in which a GPP was filed shall be filed as a separate filing at the same time as the annual GCA application to be effective October 1.
- (b) November 1 filing schedule. Black Hills/Colorado Gas Utility Company, LP; Black Hills Gas Distribution, LLC; Durango Mountain Utilities; and Colorado Natural Gas, Inc. shall file with the Commission annual GCA applications with an effective date of November 1. Additional GCA applications may also be filed as necessary pursuant to paragraph 4603(c). The GPR for the

preceding gas purchase year in which a GPP was filed shall be filed as a separate filing at the same time as the annual GCA application to be effective November 1.

- (c) All utilities shall file their GPP submittal annually on or before June 1 for the next gas purchase year beginning July 1.

**4603. Gas Cost Adjustments.**

- (a) A utility shall file an application to adjust its GCA. The GCA application shall be filed pursuant to the schedule provided in rule 4602. A utility shall file a GCA application not less than two weeks in advance of the proposed effective date.
- (b) A GCA application shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) the information required by paragraphs 4002(b) and 4002(c); and
  - (II) the information required by rule 4604. Attachments 2, 3, 5 and 6 listed in rule 4604 shall be provided in written form and shall be provided electronically, in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by the Commission staff.
- (c) If the projected gas costs have changed from those used to calculate the currently effective gas cost or if a utility's deferred gas cost balance increases or decreases sufficiently, the utility may file an application to revise its currently effective GCA to reflect such changes, provided that the resulting change to the GCA equates to at least one cent (\$0.01) per Mcf or Dth.
- (d) Applicability of the GCA. The GCA shall be applied to all utility sales gas rate schedules. A utility engaged in the provision of gas transportation service may calculate a GCA that may be applied to transportation gas rate schedules in order to reflect appropriate costs. Absent a Commission decision, a utility engaged in the provision of gas transportation service shall not be required to calculate a transportation GCA factor.
- (e) Interest on under- or over-recovery. The amount of net interest accrued on the average monthly balance in Account No. 191 (whether positive or negative), is determined by multiplying the monthly balance by an interest rate equal to the Commission-authorized customer deposit rate for gas utilities. If net interest is positive, it will be excluded from the calculation of the deferred gas cost.
- (f) Price volatility risk management costs (hedging). Costs related to gas price volatility risk management for jurisdictional gas supply may be included for recovery through the GCA, if allowed by tariffs or by Commission decision. Such costs are subject to the prudence review and standard provided in rule 4607.
- (g) Calculation of the GCA. The GCA shall be calculated to at least the accuracy of one mil per Mcf or Dth pursuant to the following formula, subject to individual GCA rule variances granted by the Commission:

$$\text{GCA} = (\text{current gas cost} + \text{deferred gas cost}) - (\text{base gas cost}).$$

**4604. Contents of GCA Applications.**

- (a) A GCA application shall meet the following requirements.
- (I) Every application shall contain attachments 1 through 9. Attachments 10 through 12 shall be filed with the annual GCA application. The attachments shall meet the requirements set out in this rule.
  - (II) The attachments shall be organized in a manner that specifically references, and responds to, the requirements contained in each subparagraph of this rule.
  - (III) Cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment shall be submitted and provided to Commission staff at the same time as the application.
  - (IV) The application shall cross-reference the proceeding numbers of the associated GPP submittals.
  - (V) When preparing attachments 10 through 12, the rate base, net operating earnings, capital structure, and cost of capital shall be calculated in conformance with the regulatory principles authorized by the Commission in the utility's most recent general rate case, including all required pro forma adjustments.
  - (VI) An explanation of all pro forma adjustments shall be provided.
- (b) GCA attachment No. 1 - GCA Summary. This attachment shall clearly illustrate all of the following principles.
- (I) The impact the utility's currently effective GCA has on each sales gas customer class and, when applicable, the gas transportation rate class on a total dollar and mil (\$0.001, minimum) per Mcf or Dth basis.
  - (II) The impact the utility's proposed GCA has on each sales gas customer class and, when applicable, gas transportation rate class on a total dollar and mil (\$0.001, minimum) per Mcf or Dth basis; and
  - (III) The percent change in total bill for a customer of average usage for each sales gas customer class. This percent change in total bill calculation shall include an itemization of the monthly service and facility charge, base rates and GCA commodity components, and all other tariff charges on the customer bill.
- (c) GCA attachment No. 2 - Current Gas Cost Calculation. This attachment shall contain the calculation of the current gas cost and shall provide month-by-month information with respect to the forecasted gas commodity cost, forecasted gas purchase quantity, forecasted market prices, forecasted upstream service cost, and forecasted sales gas quantity.
- (I) The utility shall calculate current gas cost at least to the accuracy of the nearest mil (\$0.001) per Mcf or Dth according to the following formula, subject to individual GCA rule variances granted by the Commission:

current gas cost = (forecasted gas commodity cost + forecasted upstream service cost) / forecasted sales gas quantity.

- (II) The utility shall present all such information in a format comparable with, and corresponding to, the information forecasted in the utility's GPP submittal for each month of the GCA effective period, as required pursuant to rule 4606.
- (d) GCA attachment No. 3 - Deferred Gas Cost Calculation. This attachment shall contain the details of the utility's actual gas purchase costs and the calculation of deferred gas cost. In addition, this attachment shall provide month-by-month information detailing the activity in USOA Account No. 191 by subaccount and period as applicable, interest on under- or over-recovery, and all other included gas costs authorized for recovery in the GCA. The utility shall calculate deferred gas cost as the aggregate total of the under- or over-recovered gas costs reflected in its Account No. 191, or other approved gas costs, recorded at the close of business for each month of the period at issue (such as the previous gas purchase year), plus interest on under- or over-recovery (if net amount is negative), divided by forecasted sales gas quantity. The utility shall calculate deferred gas cost at least to the accuracy of the nearest mil per Mcf or Dth. Each cost a utility includes in the deferred gas cost calculation shall be itemized and clearly identified and itemized for applicability to the period at issue. In its annual GCA applications the utility shall reflect actual deferred costs for the most recent period ending June 30, or as otherwise approved by the Commission.
- (e) GCA attachment No. 4 - Current Tariff. This attachment shall contain the tariff pages which illustrate the gas cost components of the utility's currently-effective rates for sales gas service and, where applicable, gas transportation service.
- (f) GCA attachment No. 5 - Forecasted Gas Transportation Demand. This attachment applies only to utilities that have a GCA component within their authorized rates for gas transportation service. This attachment shall provide the following information, with all demand forecast information provided on a Mcf or Dth basis:
- (I) a forecast of gas commodity throughput attributable to gas transportation service for each month of the GCA effective period; and
  - (II) a forecast of firm backup supply demand quantities (to the extent the utility has such service) under the utility's firm gas transportation service agreements for each month of the GCA effective period.
- (g) GCA attachment No. 6 - current gas cost allocations. This attachment shall fully explain and justify the method(s) used to do each of the following:
- (I) allocate the costs associated with the gas commodity and upstream services to each specific sales gas customer class and, where applicable, gas transportation customer rate class; and
  - (II) derive the amount of the GCA applied to each specific sales gas customer class and, where applicable, gas transportation customer rate classes.



- (h) GCA attachment No. 7 - Customer Notice. This attachment shall provide the form of notice to customers and the public concerning the utility's proposed GCA change. In its customer notice for each sales gas customer class, the utility shall include the following:
  - (I) current and proposed GCA rates and percentage change;
  - (II) comparison of the previous gas purchase year's last average annual bill under prior rates and the projected average annual bill under the proposed GCA rates and percentage change in the total bill amount using an average usage amount for each customer class;
  - (III) comparison of the prior year's peak winter month bill under prior rates and the projected peak winter month bill under the proposed GCA rates and percentage change using an average peak winter month usage amount for each customer class; and
  - (IV) with the annual GCA application, a statement that the utility made a separate gas purchase report filing in accordance with rule 4607 to begin the initial prudence review evaluation process for the prior gas purchase year.
- (i) GCA attachment No. 8 - components of delivered gas cost. This attachment shall detail the itemized rate components of delivered gas cost to the customer (rate), per rule 4406.
- (j) GCA attachment No. 9 - proposed tariff. This attachment shall contain the tariff sheets proposed by the utility to reflect the proposed GCA change.
- (k) GCA attachment No. 10 - rate base. This attachment shall calculate the used and useful rate base assets employed by the utility for Commission-regulated gas operations for the most recently completed 12-month period ending June 30.
- (l) GCA attachment No. 11 - net operating earnings. This attachment shall calculate the utility's net operating earnings for jurisdictional gas operations during the most recently completed 12-month period ending June 30.
- (m) GCA attachment No. 12 - capital structure and cost of capital. This attachment shall calculate the following information for the most recently completed 12-month period ending June 30, the utility's:
  - (I) capital structure for jurisdictional gas operations;
  - (II) cost of long-term debt and preferred equity;
  - (III) cost of common equity; and
  - (IV) weighted average cost of capital.

**4605. Gas Purchase Plans.**

- (a) GPP filing requirements. The utility shall file its GPP as a "Submittal for Determination of Completeness of GPP." This submittal shall include the following proceeding caption: "In the

matter of Gas Purchase Plans and Gas Purchase Reports for [utility] for the Gas Purchase Year from July 1, [year] through June 30, [year]."

- (b) Contents of GPP filing. In the GPP, the utility shall submit to the Commission the following:
  - (I) the information required by rule 4606;
  - (II) the utility's forecasted quantity of gas to be purchased over the ensuing gas purchase year for each service level;
  - (III) the utility's forecasted pricing for each receipt point/area; and
  - (IV) the utility's portfolio management plan.
- (c) Commission procedures for processing filings. Upon receipt of a GPP submittal, the Commission shall assign a proceeding number and shall review the submittal solely for completeness (i.e., compliance with the information requirements of these rules). The Commission shall not: hold a hearing on the substance of the GPP, entertain interventions by interested parties, require the filing of testimony or permit discovery. The Commission shall not render a decision approving or disapproving the substantive information contained in the submittal.
- (d) Review timelines. Commission staff shall review the submittal and, within 15 calendar days of the filing, shall provide written notification to the utility of any deficiencies in the submittal. The utility shall file the requested information, or a written statement indicating that the utility believes the additional information is not required, within 15 calendar days after the date of the Commission staff notification. Upon receipt of final information or the written statement, Commission staff shall place the submittal on the agenda for consideration at the next available Commissioners' weekly meeting. If the Commission fails to mail its determination on completeness of the submittal within 15 calendar days of receipt of final information or the written statement, the submittal shall be deemed complete.
- (e) Utilities with multiple GCA rate areas. A utility with more than one approved GCA rate area in Colorado shall file a separate GPP for each GCA rate area. These GPPs may be filed in a single submittal.
- (f) GPP no longer reflects market conditions. A utility shall file a new GPP within 30 days of its determination that the currently effective GPP no longer substantively reflects active purchasing conditions or the utility's planned purchasing practices.

**4606. Contents of the GPP.**

A GPP submittal shall contain the following attachments. The utility shall organize attachments in a manner that specifically references, and responds to, the requirements of paragraphs (a) through (d) of this rule. With its submittal, the utility shall provide cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment.

- (a) GPP attachment No. 1 - gas purchase schedule. This attachment shall provide a forecast of the specific gas commodity supplies, segregated by receipt point/area, which the utility plans to

purchase in order to meet forecasted sales gas demand during each month of the applicable gas purchase year.

- (b) GPP attachment No. 2 – gas purchasing pricing description. For each specific receipt point/area, this attachment shall provide an estimate of applicable ranges of forecast index prices expected to be incurred, short-term fixed prices (one-year or other appropriate term), and other relevant pricing options, as applicable to the portfolio management plan described in GPP attachment 3.
- (c) GPP attachment No. 3 – portfolio management plan. This attachment shall provide a plan stating how the utility plans to manage its gas supply portfolio for the gas purchase year. This attachment shall also include a description and analysis of the options the utility considered, or will consider, and the steps the utility has taken, or will take, to reduce customers' risk of gas price volatility for the gas purchase year. To the extent a utility proposes to use gas price volatility risk management tools, this attachment shall include a description of the utility's policy for implementing such risk management tools, including a projection of such costs and the assumptions underlying all cost estimates.
- (d) GPP attachment No. 4 - forecasted upstream service costs. This attachment shall include the following information for each month of the applicable gas purchase year:
  - (I) An itemized list of all upstream services, by provider and service level or rate schedule, and associated costs, that the utility expects to purchase in the upcoming gas purchase year in order to meet sales gas and gas transportation demand .
  - (II) A comparison of forecasted design peak day delivery quantity with all sources of capacity available to the utility, including forecasted upstream services, forecasted gas commodity to be purchased directly into the utility's distribution system (i.e., city gate purchases) on a firm basis, and the utility's own gas storage facilities or purchased gas storage capacity.
  - (III) A comprehensive explanation of the utility's forecasted level of planned upstream service purchases.
  - (IV) Forecasted capacity release volumes and revenues for release of upstream capacity by the utility.

**4607. Gas Purchase Reports and Prudence Reviews.**

- (a) GPR filing requirements. The utility shall file a GPR under the previous year's GPP proceeding number (filed approximately 15 months previously) as a separate filing from, and at the same time as, the annual GCA application. Specific attachments or other information may be filed under seal; however, an explanation of the confidential nature of the attachments or information must be included in the GPR filing.
- (b) Prudence review process. Based on the initial evaluation of the GPR, the Commission may initiate a prudence review hearing. The Commission shall initiate this hearing by written order within 120 days of the filing of the GPR. The prudence review may result in tariff or rate changes that could affect different classifications of customers.

- (c) Prudence review standard. For purposes of GCA recovery, the standard of review to be used in assessing the utility's action (or lack of action) in a specific gas purchase year is: whether the action (or lack of action) of a utility was reasonable in light of the information known, or which should have been known, at the time of the action (or lack of action).
- (d) Burden of proof. If the Commission elects to hold a hearing, the utility shall have the burden of proof and the burden of going forward to establish the reasonableness of actual gas commodity and demand costs paid by the utility, actual costs incurred in volatility management, and actual upstream service costs of any nature incurred during the review period.
- (e) Utility testimony and attachments. If the Commission sets a hearing, the utility shall file its testimony supporting gas cost recovery for the gas purchase year at issue. The testimony shall be filed in question-and-answer format. The utility shall file its testimony not later than 45 days after the Commission sets the matter for hearing.

**4608. Contents of the GPR.**

A GPR shall contain the following attachments. The utility shall organize the attachments in a manner that specifically references, and responds to, paragraphs (a) through (d) of this rule. The utility shall also present all such information in a format comparable with, and corresponding to, the information forecasted in the utility's GPP submittal as required pursuant to rule 4606 and GCA application pursuant to rule 4604. The utility shall provide an explanation of, and justification for, any material deviations from its GPP. All underlying support documentation and work papers shall be made available. With its filing, the utility shall provide cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment.

- (a) GPR attachment No. 1 - actual gas commodity purchases. This attachment shall provide, in a format comparable to the information provided in GPP attachment 1, the quantities of, and actual invoice costs of, specific gas commodity supplies, segregated by receipt point/area that the utility purchased in order to meet actual sales gas and gas transportation demand during the peak day and for each month of the gas purchase year.
- (b) GPR attachment No. 2 - description of actual market prices. This attachment shall provide, in a format comparable to the information provided in GPP attachment 2, actual index prices, short-term fixed prices (one-year, or other appropriate term), and other relevant pricing options for each specific receipt point area, as applicable to the portfolio management plan described in GPP and GPR attachments 3.
- (c) GPR attachment No. 3 - actual portfolio purchases. This attachments shall provide, in a format comparable to the information provided in GPP exhibit 3, a comparison of the utility's portfolio management plan and the results actually achieved through the implementation of this plan (or modification thereto), in order to demonstrate, using the standard of review specified in paragraph 4607(c), the prudence of actual portfolio purchases. This attachment shall include a detailed itemization of gas price volatility risk management costs if applicable.
- (d) GPR attachment No. 4 - actual upstream service costs. This attachment shall provide, in a format comparable to the information provided in GPP attachment 4, the following information for each month of the gas purchase year:

- (I) an itemized list of the upstream services the utility actually purchased in order to meet sales gas and gas transportation demand;
- (II) an itemized listing of the specific costs the utility incurred to purchase upstream services;
- (III) actual peak day demand experienced by the utility during the gas purchase year; and
- (IV) an itemized list of capacity release volumes and revenues.

**4609. General Provisions.**

- (a) For each attachment filed by the utility as confidential under rules 4600 through 4609, the utility shall provide, at a minimum, a version of the attachment with publicly available information.
- (b) A utility shall monitor the net under- or over-recovery balance in USOA Account No. 191 on a monthly basis. On a quarterly basis, or as otherwise established individually for a utility, a utility shall file, within 30 days of the end of the quarter, a report to the Commission stating the USOA Account No. 191 balance calculation for each rate area. The reports shall include the USOA Account No. 191 balance information specified in GCA attachment 3 and shall be filed in one common proceeding, established by the Commission to receive USOA Account No. 191 balance filings from all utilities. If the utility identifies a significant net under- or over- recovery balance during the gas purchase year, the utility shall initiate appropriate action to mitigate the significant under- or over- recovery balance.

**4610. – 4699. [Reserved].**

**APPEALS OF LOCAL GOVERNMENT LAND USE DECISIONS**

**4700. Scope and Applicability.**

Rules 4700 through 4707 apply to all utilities or power authorities which seek to appeal a local government action concerning a major natural gas facility.

**4701. Definitions.**

The following definitions apply to rules 4700 through 4707, unless a specific statute or rule provides otherwise. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- (a) "Local government" means a county, a home rule or statutory city, a town, a territorial charter city, or a city and county.
- (b) "Local government action" means (1) any decision, in whole or in part, by a local government which has the effect or result of denying a permit or application of a utility that relates to the location, construction, or improvement of a major natural gas facility or (2) a decision imposing requirements or conditions upon such permit or application that will unreasonably impair the ability of the utility to provide safe, reliable, and economical service to the public.

- (c) "Local land use decision" means the decision of a local government within its jurisdiction to plan for and regulate the use of land.
- (d) "Major natural gas facility" is defined by § 29-20-108(3)(e), C.R.S., or by any other applicable statute.
- (e) "Power authority" means an authority created pursuant to § 29-1-204, C.R.S.

**4702. Precondition to Application.**

In order for a utility or power authority to appeal a local government action to the Commission pursuant to this rule and pursuant to § 29-20-108, C.R.S., one or more of the following conditions must be met:

- (a) the utility or power authority has applied for or has obtained a certificate of public convenience and necessity from the Commission pursuant to § 40-5-101, C.R.S., to construct the major natural gas facility that is the subject of the local government action;
- (b) a certificate of public convenience and necessity is not required for the utility or power authority to construct the major natural gas facility that is the subject of the local government action; and
- (c) the Commission has previously entered an order pursuant to § 40-4-102, C.R.S., that conflicts with the local government action.

**4703. Applications.**

- (a) To commence an appeal of a local government land use decision, a utility or power authority shall file with the Commission an application pursuant to this rule.
- (b) An application filed in accordance with §§ 29-20-108, C.R.S., and this rule shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) all of information required in paragraphs 4002(b) and 4002(c);
  - (II) a showing that one of the preconditions set out in rule 4702 has been met;
  - (III) identification of the major natural gas facility;
  - (IV) identification of the local government action and its impact on the major natural gas facility;
  - (V) a statement of the reasons the applying utility or power authority believes that the local government action would unreasonably impair its ability to provide safe, reliable, and economical service to the public;
  - (VI) the demonstrated need for the major natural gas facility or reference to the application made to the Commission with respect to the major natural gas facility and the resulting decision of the Commission regarding such facility;

- (VII) the extent to which the proposed facility is inconsistent with existing applicable local or regional land use ordinances, resolutions, or master or comprehensive plans;
- (VIII) whether the proposed facility would exacerbate a natural hazard;
- (IX) applicable utility engineering standards, including supply adequacy, system reliability, and public safety standards;
- (X) the relative merit, as determined through use of the normal system planning evaluation techniques of the utility or power authority, of any reasonably available and economically feasible alternatives proposed by the utility, the power authority, or the local government;
- (XI) the impact that the local government action would have on the customers of the utility or power authority who reside within and without the boundaries of the jurisdiction of the local government;
- (XII) the basis for the local government action. If available, the utility or power authority shall attach a copy of the local government action;
- (XIII) the impact the proposed facility would have on residents within the local government's jurisdiction including, in the case of a right-of-way in which facilities have been placed underground, whether those residents have already paid to place such facilities underground. If the residents have already paid to place facilities underground, the Commission will give strong consideration to that fact;
- (XIV) information concerning how the proposed major natural gas facility will affect the safety of residents within and without the boundaries of the jurisdiction of the local government; and
- (XV) an attestation that the utility or power authority will, upon filing the application with the Commission, simultaneously send the application to the local government body which took the local government action which is the subject of the appeal.

**4704. Public Hearing.**

In addition to the formal evidentiary hearing on the appeal, and pursuant to § 29-20-108(5)(b), C.R.S., the Commission shall take statements from the public concerning the appealed local government action at a public hearing held at a location specified by the local government.

**4705. Prehearing Conference, Parties, and Public Notice.**

- (a) In order to assist the parties in scheduling the public hearing, determining the scheduling of the evidentiary hearing, developing the list of persons to receive notice of these hearings, and addressing other pertinent issues, the Commission will hold a prehearing conference.
- (b) The Commission shall conduct a prehearing conference within 15 days after the application is deemed complete by the Commission.

- (c) The Commission shall join as an indispensable party the local government which took the contested local government action.
- (d) Ten days before the commencement of the prehearing conference, the local government shall submit to the parties and the Commission its preference for the location of the public hearing to be held in accordance with § 29-20-108(5)(b), C.R.S., and rule 4704.
- (e) The Commission will decide the date and time of the public hearing after receiving comments from the parties at the prehearing conference.
- (f) By the date of the prehearing conference, each party shall provide to the utility a list of individuals and groups to receive notice of the public hearing.
- (g) The utility or power authority shall give notice of the public hearing to the identified individuals and groups in a manner specified by the Commission. Notice may be accomplished by newspaper publication, bill insert, first class mail, or any other manner deemed appropriate by the Commission.
- (h) If the local government is unable to provide meeting space for the public hearing, and space needs to be acquired, then the utility or power authority shall bear any cost associated with the rental of such space for the public hearing.
- (i) The parties are encouraged to confer prior to the prehearing conference to develop a schedule for the filing of testimony and the dates for the formal evidentiary hearing.

**4706. Denial of Appeal.**

In accordance with § 29-20-108(5)(e), C.R.S., the Commission shall deny an appeal of a local government action if the utility or power authority has failed to comply with the following notification and consultation requirements:

- (a) A utility or power authority shall notify the affected local government of its plans to site a major natural gas facility within the jurisdiction of the local government prior to submitting the preliminary or final permit application, but in no event later than filing a request for a certificate of public convenience and necessity pursuant to Article 5 of Title 40, C.R.S., or the filing of any annual filing with the Commission that proposes or recognizes the need for construction of a new major natural gas facility or the extension of an existing facility. If a utility or power authority is not required to obtain a certificate of public convenience and necessity pursuant to Article 5 of Title 40, C.R.S., or to file annually with the Commission to notify the Commission of proposed construction of a new major natural gas facility or the extension of an existing facility, then the utility or power authority shall notify any affected local governments of its intention to site a new major natural gas facility within the jurisdiction of the local government when such utility or power authority determines that it intends to proceed to permit and to construct the facility. Following such notification, the utility or power authority shall consult with the affected local governments in order to identify the specific routes or geographic locations under consideration for the site of the major natural gas facility and to attempt to resolve land use issues that may arise from the contemplated permit application.



- (b) In addition to its preferred alternative within its permit application, the utility or power authority shall consider and present reasonable siting and design alternatives to the local government or shall explain why no reasonable alternatives are available.

#### **4707. Procedural Rules.**

Pursuant to § 29-20-108(5)(b), C.R.S., any appeal brought by a utility or power authority under this section shall be conducted in accordance with the procedural requirements of Article 6, Title 40, C.R.S., including § 40-6-109.5, C.R.S. Evidentiary hearings on any such appeals shall be conducted in accordance with § 40-6-109, C.R.S.

#### **4708. – 4749. [Reserved].**

### **DEMAND SIDE MANAGEMENT**

#### **4750. Overview and Purpose.**

These rules implement §§ 40-1-102, 40-3.2-101, 40-3.2-103, and 40-3.2-105, C.R.S. for LDCs required by statute to be rate-regulated. Consistent with statutory requirements, the purpose of these Demand Side Management (DSM) rules is to reduce end-use natural gas consumption in a cost effective manner, in order to save money for consumers and utilities, and protect the environment by encouraging the reduction of emissions and air pollutants. These rules direct natural gas utilities in the design and implementation of programs that will enable sales customers to participate in DSM. The LDC shall design DSM programs for its full service customers to achieve cost-effective energy savings, considering factors such as: achievable energy savings, customer benefits, cost effectiveness ratios, adoption potential, market transformation capability and ability to replicate in the utility service territory.

- (a) Each utility shall file an application for approval of a DSM plan within the parameters set forth in these rules. In the application, the utility shall include a proposed expenditure target, savings target, funding mechanism, and cost-recovery mechanism.
- (b) Each utility shall annually file an advice letter or application for cost recovery, as permitted herein.
- (c) Each utility shall annually file a DSM report. The DSM report shall include the results of any measurement and verification (M&V) evaluation conducted during the DSM report period.

#### **4751. Definitions.**

The following definitions apply to rules 4750 through 4760, unless § 40-1-102 provides otherwise.

- (a) “Amortization” means the systematic spreading of expenditures or capital costs incurred for DSM programs, through regular accounting entries over a specified period of time.
- (b) “Benefit/cost ratio” means the ratio of the net present value of benefits to the net present value of costs, as calculated using the modified TRC test.
- (c) “Cost effective” means a benefit/cost ratio of greater than one.

- (d) “Demand side management” (DSM) means the implementation of programs or measures which serve to shift or reduce the consumption of, or demand for, natural gas.
- (e) “Discount rate” means the interest rate used in determining the present value of future cash flows of DSM costs and benefits, for both forecasted and actual cash flows. The forecasted DSM costs and benefits are used to estimate the cost effectiveness of DSM measures to develop a cost effective DSM portfolio. The actual DSM costs and benefits, which are the actual costs of the program and the documented energy savings, are used to determine net economic benefits for the purpose of calculating the bonus. Discount rate shall be the utility’s after-tax weighted average cost of capital (WACC).
- (f) “DSM education” means a program, including but not limited to an energy audit, that contributes indirectly to a cost-effective DSM program by promoting customer awareness and participation.
- (g) “DSM measure” means an individual component or technology, such as attic insulation or replacement of equipment.
- (h) “DSM period” means the effective period of an approved DSM plan.
- (i) “DSM plan” means the DSM programs, goals, and budgets over a specified DSM period, generally considered in one year increments, as may be proposed by the utility.
- (j) “DSM program” means any combination of DSM measures, information and services offered to customers to reduce natural gas usage.
- (k) “Energy efficiency program” see DSM program.
- (l) “Gas Demand-Side Management Cost Adjustment” (G-DSMCA) means a rate adjustment mechanism designed to compensate a utility for its DSM program costs.
- (m) “Gas Demand-Side Management bonus” (G-DSM bonus) means a bonus awarded to a utility in accordance with § 40-3.2-103(2)(d), C.R.S.
- (n) “Market transformation” means a strategy for influencing the adoption by consumers of new techniques or technologies. The objective is to overcome barriers within a market through coordinating tactics such as education, training, product demonstration and marketing, often conducted in concert with rebates or other financial incentives.
- (o) “Modified Total Resource Cost test” or “modified TRC test” means an economic cost-effectiveness test used to compare the net present value of the benefits of a DSM program or measure over its useful life, to the net present value of costs of a DSM measure or program for the participant and the utility, consistent with § 40-1-102(5), C.R.S. In performing the modified TRC test, the benefits shall include, but are not limited to, as applicable: the utility’s avoided production, distribution and energy costs; the participant’s avoided operating and maintenance costs; the valuation of avoided emissions; and non-energy benefits as set forth in rule 4753. Costs shall include utility and participant costs. The utility costs shall include the net present value of costs incurred in accordance with the budget set forth in rule 4753.

- (p) “Net economic benefits” means the net present value of all benefits in the modified TRC test, as applied to the utility’s portfolio of DSM programs, less the net present value of the costs in the modified TRC test associated with that same portfolio.
- (q) “Sales customer” or “full service customer” means a residential or commercial customer that purchases a bundled natural gas supply and delivery service from a utility but does not include customers served under a utility’s gas transportation service rate schedules.

**4752. Filing Schedule.**

- (a) Each utility shall implement and maintain its DSM plan and G-DSMCA, as approved by the Commission.
- (b) Each utility shall submit its annual DSM report on or before April 1 of each year.
- (c) Each utility seeking a G-DSM bonus shall file an application pursuant to rule 4760 requesting approval of such bonus on or before April 1 of each year.
- (d) Each utility shall file an advice letter on or before May 31 of each year to adjust the G-DSMCA to be effective July 1 for a period of 12 months. Alternatively, each utility may file a combined application on or before April 1 of each year seeking a G-DSM bonus, as well as an adjustment to the G-DSMCA, to be effective July 1 for a period of 12 months.
- (e) By May 1 of the final year of the currently effective DSM plan, each utility shall file by application a prospective natural gas DSM plan for Commission approval.

**4753. Periodic DSM Plan Filing.**

Each utility shall periodically file, in accordance with paragraph 4752(e), a prospective natural gas DSM plan that covers a DSM period of three years, unless otherwise ordered by the Commission. The plan shall include the following information:

- (a) the utility’s proposed expenditures by year for each DSM program, by budget category; the sum of these expenditures represents the utility’s proposed expenditure target as required by § 40-3.2-103(2)(a), C.R.S.;
- (b) the utility’s estimated natural gas energy savings over the lifetimes of the measures implemented in a given annual DSM program period, expressed in dekatherms per dollar of expenditure, and presented for each DSM program proposed for Commission approval; this represents the utility’s proposed savings target required by § 40-3.2-103(2)(b), C.R.S.;
- (c) the anticipated units of energy to be saved annually by a given annual DSM program, which equals the product of the proposed expenditure target and proposed savings target; this product is referred to herein as the energy target;
- (d) the estimated dollar per therm value that represents the utility’s annual fixed costs that are recovered through commodity sales on a per therm basis;

- (e) the utility shall include in its DSM plan application data and information sufficient to describe the design, implementation, oversight and cost effectiveness of the DSM programs. Such data and information shall include, at a minimum, program budgets delineated by year, estimated participation rates and program savings (in therms);
- (f) in the information and data provided in a proposed DSM plan, the utility shall reflect consideration of the factors set forth in the Overview and Purpose, rule 4750. At a minimum the utility shall provide the following information detailing how it developed its proposed DSM program:
  - (I) descriptions of identifiable market segments, with respect to gas usage and unique characteristics;
  - (II) a comprehensive list of DSM measures that the utility is proposing for inclusion in its DSM plan;
  - (III) a detailed analysis of proposed DSM programs for a utility's service territory in terms of markets, customer classes, anticipated participation rates (as a number and a percent of the market), estimated energy savings and cost effectiveness;
  - (IV) a ranking of proposed DSM programs, from greatest value and potential to least, based upon the data required in subparagraph (f)(III);
  - (V) proposed marketing strategies to promote participation based on industry best practices;
  - (VI) calculation of cost effectiveness of the proposed DSM programs using a modified TRC test. Each proposed DSM program is to have a projected value greater than or equal to 1.0 using a modified TRC test, except as provided for in paragraph 4753 (g);and
  - (VII) an analysis of the impact of the proposed DSM program expenditures on utility rates, assuming a 12-month cost recovery period.
- (g) In its DSM plan, the utility shall address how it proposes to target DSM services to low-income customers. The utility shall also address whether it proposes to provide DSM services directly or indirectly through financial support of conservation programs for low-income households administered by the State of Colorado, as authorized by § 40-3.2-103(3)(a), C.R.S. The utility may propose one or more low-income DSM programs that yield a modified TRC test value below 1.0.
- (h) In proposing an expenditure target for Commission approval, pursuant to § 40-3.2-103 (2)(a), C.R.S., the utility shall comply with the following:
  - (I) the utility's annual expenditure target for DSM programs shall be, at a minimum, two percent of a natural gas utility's base rate revenues, (exclusive of commodity costs), from its sales customers in the 12-month calendar period prior to setting the targets, or one-half of one percent of total revenues from its sales customers in the 12-month calendar period prior to setting the targets, whichever is greater;
  - (II) the utility may propose an expenditure target in excess of two percent of base rate revenues; and

- (III) funds spent for education programs, market transformation programs and impact and process evaluations and program planning related to natural gas DSM programs may be recovered without having to show that such expenditures, on an independent basis, are cost-effective; such costs shall be included in the overall benefit/cost ratio analysis.
- (i) The utility shall propose a budget to achieve the expenditure target proposed in paragraph 4753 (a). The budget shall be detailed for the overall DSM plan and for each program for each year and shall be categorized into:
  - (I) planning and design costs;
  - (II) administrative and DSM program delivery costs;
  - (III) advertising and promotional costs, including DSM education;
  - (IV) customer incentive costs;
  - (V) equipment and installation costs;
  - (VI) measurement and verification costs; and
  - (VII) miscellaneous costs.
- (j) The budget shall explain anticipated increases/decreases in financial resources and human resources from year to year.
- (k) A utility may spend more than the annual expenditure target established by the Commission up to 25 percent over the target, without being required to submit a proposed DSM plan amendment. A utility may submit a proposed DSM plan amendment for approval when expenditures are in excess of 25 percent over the expenditure target.
- (l) As a part of its DSM plan, each utility shall propose a DSM plan with a benefit/cost value of unity (1) or greater, using a modified TRC test.
- (m) For the purposes of calculating a modified TRC, the non-energy benefits of avoided emissions and societal impacts shall be incorporated as follows.
  - (I) The initial TRC ratio, which excludes consideration of avoided emissions and other societal benefits, shall be multiplied by 1.05 to reflect the value of the avoided emissions and other societal benefits. The result shall be the modified TRC. A utility may propose for approval a different factor for avoided emissions and societal impacts, but must submit documentation substantiating the proposed value.
- (n) Measurement and verification (M & V) plan. The utility shall describe in complete detail how it proposes to monitor and evaluate the implementation of its proposed programs. The utility shall explain how it will accumulate and validate the information needed to measure the plan's performance against the standards, pursuant to rule 4755. The utility shall propose measurement and verification reporting sufficient to communicate results to the commission in a detailed, accurate and timely basis.

**4754. Annual DSM Report and Application for Bonus and Bonus Calculation.**

On the schedule set forth in rule 4752, the utility shall provide the Commission a detailed DSM report and application for bonus.

- (a) In the annual DSM report, the utility shall describe its actual DSM programs as implemented. For each DSM program, the utility shall document actual program expenditures, energy savings, participation levels and cost-effectiveness.
- (b) Annual program expenditures shall be separated into cost categories contained in the approved DSM plan.
- (c) For each DSM program, the utility shall compare the program's proposed and actual expenditures, savings, participation rate, and cost-effectiveness; in addition, the utility shall prepare an assessment of the success of the program, and list any suggestions for improvement and greater customer involvement.
- (d) The utility shall provide actual benefit/cost results for the overall DSM plan and individual DSM programs implemented during the plan year. The benefit/cost analysis shall be based on the costs incurred and benefits achieved, as identified in the modified TRC test. Benefit values are to be based upon the results of M & V evaluation, when such has been conducted as set forth in rule 4755. Otherwise, the benefit values of the currently approved DSM plan are to be used.
- (e) If the annual report covers a year within which an M & V evaluation was completed, the complete M & V results are to be included as part of the annual report.
- (f) The utility may file an application for bonus, pursuant to rule 4760. The application for bonus shall include the utility's calculation of estimated bonus applying the methodology set forth in this rule to the utility's actual performance.
- (g) The Commission shall determine the level of bonus, if any, that the utility is eligible to collect on the basis of the information included in the report, pursuant to the bonus criteria and process set forth, below.
  - (l) The primary objective of the bonus is to encourage cost-effective energy savings. The amount of bonus earned, if any, will correlate with the utility's performance relative to the approved savings target (dekatherms saved per dollar expended) and the energy target. Assuming all other factors that affect consumption remain unchanged, effective DSM programs will reduce per customer commodity consumption, which may lead to revenue reductions for the utility. The utility may include in the bonus application a request for approval to recover a calculated amount of revenue that acknowledges the DSM program reduced the utility's revenue. The recovery amount for reduced revenue is separate from any bonus determined by the Commission and shall be calculated, as follows:
    - (A) the utility shall calculate a dollar per therm value that represents the utility's annualized fixed costs that are recovered through commodity sales on a per therm basis;

- (B) the utility shall include in the DSM filing pursuant to rule 4753 a proposed dollar per therm value with the calculation methodology and supporting documentation;
  - (C) the recovery amount for reduced revenue shall be calculated by multiplying the dollar per therm value by the annualized number of therms saved and reported in the utility's annual DSM report for the plan year;
  - (D) the recovery of the reduced revenue amount shall be through the Demand-Side Management Cost Adjustment (DSMCA), over the same twelve month period in which any approved bonus amount is recovered, as set forth in subparagraph 4752 (b)(l); and
  - (E) for the purpose of inclusion in the above calculation, the annual report shall include the number of therms projected to be saved from the DSM programs in the twelve months following the end of the program year.
- (II) As a threshold matter, the utility must expend at least the minimum amount set forth in subparagraph 4753 (h)(l), in order to earn a bonus.
- (III) The bonus amount is a percentage of the net economic benefits resulting from the DSM plan over the period under review. The percentage value is the product of the two factors:
- (A) The Energy Factor is determined by the percentage of the energy target achieved by the utility. The energy factor is zero plus 0.5 percent for each one percent above 80 percent of the energy target achieved by the utility.
  - (B) The Savings Factor is the actual savings achieved divided by the approved savings target. The actual savings achieved and approved savings target are each expressed in dekatherms saved per dollar expended.
- (IV) The following is provided as an example of the bonus calculation, using these illustrative numbers: utility achieves 106 percent of its energy target; the utility's savings target is 15,000 dekatherms per \$1 million expended, and the utility's actual savings is 18,000 dekatherms per \$1 million.
- The energy factor would be:  $50 \text{ percent} \times (106 - 80)$ , or 13 percent
- The savings factor would be:  $18,000/15,000$  or 1.2
- The resulting bonus percentage would be:  $13 \text{ percent} \times 1.2$ , or 15.6 percent. Thus, 15.6 percent of net economic benefits would be the bonus amount.
- (h) For the purposes of calculating the bonus, the costs and benefits associated with DSM programs targeted to low-income customers may be excluded as follows:
- (l) the costs and benefits associated with a low-income DSM program may be excluded from the calculation of the net economic benefits for the entire DSM portfolio if the modified TRC value for the low-income program is below 1.0; and

- (II) the expenditures and therms saved associated with a low-income DSM program may be excluded from the calculation of the Savings Factor if the therms saved per dollar expended for the low-income program is below the approved savings target for the overall DSM portfolio.
- (i) The maximum bonus is 20 percent of net economic benefits or 25 percent of expenditures, whichever is less.
- (j) Any awarded bonus shall be authorized as a supplement to a utility and not count against its authorized rate of return or be considered in rate proceedings. The awarded bonus shall be recovered through the G-DSMCA over a 12-month period after approval of the bonus.

**4755. Measurement and Verification.**

- (a) Each utility shall implement a measurement and verification (M & V) program to evaluate the actual performance of its DSM program. The utility shall present its M & V plan as a part of its DSM plan application, pursuant to rule 4753, and shall include the complete M & V evaluation results with its annual DSM report in those years when the M & V is conducted.
- (b) As a part of its M & V program, the utility shall, at a minimum, design a M & V plan to evaluate the effectiveness of the actual DSM measures and programs implemented by the utility. The M & V plan shall address: sampling bias; a data gathering process sufficient to yield statistically significant results; and generally accepted methods of data analysis. The M & V plan shall also include an evaluation of free ridership, spillover and the net-to-gross ratio. The M & V evaluation shall be implemented at least once per the DSM plan period. Subsequent DSM plan applications shall reflect the results of all completed M & V evaluations.
- (c) The M & V evaluation shall, at a minimum, include the following:
  - (I) an assessment of whether the DSM programs have been implemented as set forth in its Commission approved DSM plan;
  - (II) a measurement of the actual energy savings for each DSM program, in dekatherms per dollar expended and in total dollars, and a comparison to the corresponding utility projections in the approved DSM plan;
  - (III) to the extent feasible, an assessment of the period of time that each DSM measure actually remains in service, and a comparison to the corresponding utility projections in the approved DSM plan;
  - (IV) a summary of the actual benefit/cost ratio for each DSM program within the approved DSM plan;
  - (V) an assessment of the extent to which education and market transformation efforts are achieving the desired results; and
  - (VI) recommendations for how the utility can improve the market penetration and cost effectiveness of individual DSM programs.



**4756. General Provisions Concerning Cost Allocation and Recovery.**

- (a) Amortization periods.
  - (I) For the base rate method, the utility shall propose the amortization period. The utility shall specify and explain the rationale for the amortization period proposed for each DSM program as a part of its DSM plan application, filed pursuant to rule 4753.
  - (II) For the expense method, the utility shall recover the annual expenditures projected for that year over a one-year period.
- (b) Fuel switching. Fuel switching from natural gas to other fossil fuel derived energy sources shall not be included in the gas utility's DSM program. Programs to save natural gas through switching to renewable energy sources such as solar heating and ground source heat pumps are allowed.
- (c) A utility that provides both regulated gas and electric service shall give consideration to the administrative benefits and reduced costs associated with combining gas and electric DSM activities and shall assign costs and benefits appropriately to each plan.
- (d) Distribution of DSM program expenses.
  - (I) The utility shall include in its portfolio-level benefit/cost analysis all indirect costs relating to DSM, including but not limited to DSM customer education, program design, and evaluation costs.
  - (II) A utility's existing gas efficiency and conservation customer education tools, such as on-line energy assessment tools or other similar internet based tools, may be included in a utility's gas DSM plan and costs recovered pursuant to the gas DSMCA rule.

**4757. Funding and Cost Recovery Mechanism.**

The purpose of the G-DSMCA is to enable utilities to recover prudently incurred gas DSM program expenses without requiring a change in their base rates for gas sales. All such costs, plus any G-DSM bonus approved by the Commission, shall be recovered through the G-DSMCA that is set on an annual basis, and collected from July 1 through June 30. The G-DSMCA allows for prospective recovery of prudently incurred costs of DSM programs within the DSM program expenditure target approved by the Commission in order to provide for funding of the utility's DSM programs, as well as recovery of deferred G-DSMCA costs, without having to file a rate case.

- (a) A utility may spend a disproportionate share of total expenditures on one or more classes of customers, provided, however, that cost recovery for programs directed at residential customers are to be collected from residential customers only and that cost recovery for programs directed at nonresidential customers are to be collected from nonresidential customers only, except as provided for in paragraph 4757 (f).
- (b) The utility may recover its DSM program expenditures either through expensing or by adding DSM program expenditures to base rates as a part of, or outside of, a rate case, with an amortization period as set forth in rule 4756.

- (c) There shall be no financial penalty assessed on a utility for failing to reach its approved DSM program expenditure target, nor shall there be a bonus simply for meeting its DSM program expenditure target. All prudently incurred expenditures for the utility's portfolio of DSM programs are recoverable. However, the portion of costs yielding a modified TRC test value below 1.0 loses its presumption of prudence and is subject to review.
- (d) Amounts not spent under the DSM program expenditure target shall not roll-over to the next DSM period.
- (e) A utility has the discretion and the responsibility of managing the portfolio of DSM programs to meet the benefit to cost ratio and the energy and savings targets. In implementing DSM programs, a utility shall use reasonable efforts to maximize energy savings consistent with the approved DSM plan.
- (f) A utility may continue DSM programs that were in existence on or before May 22, 2007, the effective date of § 40-3.2-103, C.R.S., concerning measures to promote energy efficiency, and shall not be required to obtain approval from the Commission for recovery of costs associated with such programs. Any new expenditure for such programs must be included in the annual DSM plan filing and G-DSMCA application. Existing low-income DSM programs that recover costs from all customer classes shall continue such recovery.
- (g) A utility shall file a request to adjust its G-DSMCA factor either through an application or an advice letter and tariffs, pursuant to the relevant provisions of title 40, articles 1 through 7 of the Colorado Public Utilities Law and of the Commission rules. The G-DSMCA shall be filed pursuant to the schedule provided in rule 4752.
- (h) The G-DSMCA filing shall include information and attachments as required in rule 4758. If the M & V evaluation required by rule 4755 yields benefit/costs test results that impact the allowable recovery of costs or currently approved bonus, then the utility shall include such adjustments in the G-DSMCA filing and tariffs.
- (i) If the projected DSM program costs have changed from those used to calculate the currently effective G-DSMCA cost or if a utility's deferred G-DSMCA cost balance increases or decreases sufficiently, the utility may file an application to revise its currently effective G-DSMCA factor to reflect such changes, provided that the resulting change to the G-DSMCA factor equates to a base rate change of at least one cent (\$0.01) per Mcf or Dth. A utility has the burden of proof to justify any interim G-DSMCA filings and the Commission has the discretion to consolidate the interim G-DSMCA filing with the next regularly scheduled annual G-DSMCA filing.
- (j) Applicability of the G-DSMCA factor. The G-DSMCA factor shall be separately calculated and applied to the utility sales gas base rate schedules of residential and non-residential customers.
- (k) Return on DSM program expenditures to be amortized. For utilities that choose to amortize the DSM program expenditure, the balance of a utility's investments in cost-effective DSM programs shall earn a return equal to the utility's current after-tax weighted average cost of capital.

- (l) Interest on under- or over-recovery. The amount of net interest accrued on the average monthly balance in sub-accounts of Account No. 186 (whether positive or negative), is determined by multiplying the monthly balance by an interest rate equal to the Commission-authorized after-tax weighted average cost of capital.
- (m) Calculation of the G-DSMCA factor. The G-DSMCA factor shall be calculated separately for residential and non-residential customers to at least the accuracy of two significant places.

**4758. Contents of Gas DSM Cost Adjustment Filing.**

- (a) General Provisions.
  - (I) A filing for a gas DSM cost adjustment (G-DSMCA) shall contain justifying information sufficient in detail to permit the Commission to determine the accuracy of the supporting calculation.
  - (II) The G-DSMCA filing shall include a complete set of work papers and all other documents relied on in preparing the adjustment.
  - (III) The provisions of this rule do not supersede other Commission rules that contain additional applicable filing requirements.
- (b) Specific Provisions. The filing shall contain detailed schedules and supporting documents that establish, at a minimum, the following:
  - (I) the detailed calculation of the G-DSMCA for each customer class based on the following general formula:
    - (A)  $\text{current G-DSMCA factor} = (\text{current G-DSMCA cost} + \text{deferred G-DSMCA cost}) / (\text{forecasted sales customer} \times \text{monthly service charge} + \text{forecasted sales gas quantity} \times \text{base rate});$  and
    - (B) the G-DSMCA factor will also include the current G-DSM bonus plus any adjustment necessary to previously approved G-DSM bonuses;
  - (II) a detailed schedule showing the computation of interest, as applicable, to deferred amounts;
  - (III) the absolute and percentage impact of the proposed rate on the base rates and on the total monthly bills of typical customers in each customer class;
  - (IV) a schedule detailing the allocation of costs to each customer class;
  - (V) proposed customer notice detailing rate impact and effective date;
  - (VI) proposed tariff implementing the proposed G-DSMCA; and

- (VII) if any gas DSM costs are proposed to be recovered by rate base treatment, with a return on the unamortized balance, a statement of current net operating earnings, a detailed calculation of the related revenue requirement and an attachment detailing any differences in the proposed rate base treatment compared to the regulatory practices employed by the Commission in its last general rate case for the applicant.

**4759. Bill Itemization.**

Consistent with rule 4406, a utility shall provide itemized gas cost information with gas DSM costs to all customers commencing with the first complete billing cycle in which the new rates are in effect.

**4760. Gas DSM Bonus (G-DSM Bonus) Applications.**

The Commission shall review each G-DSM bonus application submitted and shall determine the level of bonus, if any, for which the utility is eligible. The collection on any G-DSM bonus awarded will be apportioned between residential and nonresidential customers based on the proportion of residential and nonresidential net economic benefits used to calculate the G-DSM bonus.

- (a) G-DSM bonus filing requirements. The utility shall file its G-DSM bonus application as part of the annual report submitted to the Commission on the timetable set forth in rule 4752. The utility may request a G-DSM bonus not to exceed the lower of 25 percent of the expenditures or 20 percent of the net economic benefits of the DSM programs, applying the bonus calculation procedure set forth in rule 4754. The G-DSM bonus, as modified and approved by the Commission, shall not count against a gas utility's authorized rate of return or be considered as net operating earnings in rate proceedings.
- (b) Contents of G-DSM bonus filing. In the G-DSM bonus filing, the utility shall submit to the Commission the following, at a minimum:
  - (I) documented expenditures on DSM programs for the current G-DSMCA period;
  - (II) gas savings for the calendar year for which the bonus is to be awarded estimated following and the techniques approved in the DSM plan. The utility shall explain whether the actual gas savings are validated through the measurement and verification process as approved in the utility's DSM plan;
  - (III) estimated cost-effectiveness of program expenditures for the current G-DSMCA period in terms of the amount of gas saved per unit of program expenditures;
  - (IV) actual gas savings and the techniques used to calculate these gas savings for the prior G-DSMCA period. The utility shall explain whether the actual gas savings are validated through the measurement and verification process, pursuant to rule 4755;
  - (V) actual cost-effectiveness of program expenditures for the prior G-DSMCA period in terms of the amount of gas saved per unit of program expenditures. The utility shall explain whether the actual cost effectiveness of program expenditures is validated through the measurement and verification process, pursuant to rule 4755; and
  - (VI) proposed tariffs containing rates to collect the bonus over 12 months.

- (c) The Commission shall issue a decision approving, modifying, or disapproving a DSM bonus application within 90 days of the utility filing of the application. The Commission shall allow oral testimony and shortened discovery response times as necessary to expedite the schedule.
- (d) Accounting for G-DSM bonus. Accounting for G-DSM bonus shall follow what has been prescribed for G-DSMCA costs, specifically in regard to interest on over- and under- recovery. A separate sub-account in Account No. 186 shall be created for any deferred G-DSM bonus amount.
- (e) Prudence review and adjustment of G-DSM bonus. If the Commission finds that the actual performance varies from performance values used to calculate the G-DSM bonus in rule 4754, then an adjustment shall be made to the amount of G-DSM bonus award. Any true-up in G-DSM bonus will be implemented on a prospective basis.

**4761. – 4799. [Reserved]**

**MASTER METER OPERATORS**

**4800. Scope and Applicability.**

These rules are applicable to any person who purchases gas service from a serving utility for the purpose of delivery of that service to end-users whose aggregate usage is measured by a master meter or other composite measurement device.

**4801. Definitions.**

The following definitions apply to rules 4800 through 4805, unless a specific statute or rule provides otherwise. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- (a) "Check-meter" means a meter or other composite measurement device used by a master meter operator to determine gas consumption by end-users served by the master meter operator.
- (b) "Master meter" means a meter or other composite measurement device which a serving utility uses to bill a master meter operator.
- (c) "Master meter operator" (MMO) means a person who purchases gas service from a serving utility for the purpose of delivering that service to end-users whose aggregate usage is measured by a master meter.
- (d) "Refund" means a refund, rebate, rate reduction, or similar adjustment.
- (e) "Serving utility" means the utility from which the master meter operator receives the gas service which the master meter operator then delivers to end-users.

**4802. Exemption from Rate Regulation.**

- (a) Pursuant to § 40-1-103.5, C.R.S., and by this rule, the Commission exempts from rate regulation under Articles 1 to 7 of Title 40, C.R.S., a master meter operator which is in compliance with rules 4803 and 4804.
- (b) A master meter operator which is not in compliance with rules 4803 and 4804 is subject to rate regulation under Articles 1 to 7 of Title 40, C.R.S., and shall comply with the applicable rules.

**4803. Exemption Requirements.**

- (a) In order to retain its exemption from rate regulation, a MMO shall do the following.
  - (I) As part of its billing for utility service, the MMO shall charge its end-users only the actual cost billed to the MMO by the serving utility. The MMO shall not charge end-users for any other costs (such as, without limitation, the costs of construction, maintenance, financing, administration, metering, or billing for the equipment and facilities owned by the MMO) in addition to the actual costs billed to the MMO by the serving utility.
  - (II) If the MMO bills its end-users separately for service, the sum of such billings shall not exceed the amount billed to the MMO by the serving utility.
  - (III) If the MMO bills its end-users separately for service, the MMO shall pass on to its end-users all refunds the MMO receives from the serving utility or otherwise.
  - (IV) The MMO shall establish procedures for giving notice of a refund to those who are not current end-users but who were end-users during the period for which the refund is paid.
  - (V) A master meter operator shall retain, for a period of not less than three years, all records of original utility billings made to the master meter operator and all records of billings and refunds made by the master meter operator to its end-users, including certification of mailing, when applicable.
- (b) In order to retain its exemption from rate regulation, a MMO shall not resell the services provided by a serving utility to the MMO for profit. Resale of services provided by a serving utility to a MMO for profit is a basis for revocation of an exemption from rate regulation.
- (c) A MMO may check-meter tenants, lessees, or other persons to whom the gas ultimately is distributed but may do so only if the following conditions are met:
  - (I) the check-meter is used solely for the purpose of determining a basis for the MMO to allocate the costs of the serving utility; and
  - (II) the MMO does not receive more than the actual amount billed to the MMO by the serving utility from the MMO's customers.

**4804. Refunds.**

- (a) When a serving utility notifies a MMO of a refund or when a refund is otherwise made related to the services provided by the serving utility to the MMO, a MMO shall refund an allocated share of the refunds to its customers within 90 days after receipt of the notice or refund from the serving utility. The notification shall be made either by first-class mail with a certificate of mailing or by inclusion in any monthly or more frequent regular written communication. The MMO shall retain the certification of mailing pursuant to subparagraph 4803(a)(V). The MMO shall also notify former customers who were end-users during the period for which the refund is made that refunds are available, to the extent such former customers can be located.
- (b) A MMO may retain any portion of a refund which is related to service taken by the MMO at its own facilities after refunds are made to its current and former customers.
- (c) If the aggregate amount of a refund which remains unclaimed after 90 days exceeds \$100, the MMO shall contribute that unclaimed amount to the energy assistance organization in accordance with rules 4410(d), (f), and (g). If the aggregate amount which remains unclaimed after 90 days does not exceed \$100, the MMO may retain the aggregate amount.

**4805. Complaints, Penalties, and Revocation of Exemption.**

- (a) Pursuant to rules 1301 and 1302, a person (including without limitation anyone taking service from a master meter operator) may make an informal complaint to the Commission or may file a formal complaint with the Commission with the respect to an alleged violation of rules 4803 and 4804.
- (b) As a result of a complaint or on its own motion, the Commission will investigate complaints concerning MMOs. If the Commission determines after investigation that an MMO has violated any of the requirements of rules 4803 and 4804, the MMO may have its exempt status revoked or may be subject to penalties as set forth in § 40-7-107, C.R.S., or both.

**4806. – ~~4899975.~~ [Reserved].**

**GAS PIPELINE SAFETY**

**General Provisions**

**~~4900.—Scope and Applicability.~~**

- ~~(a) — The gas pipeline safety rules prescribe requirements for construction, operation, and maintenance of pipeline facilities, and for reporting by operators. Pursuant to these rules, the Commission conducts its pipeline safety program activities under 49 U.S.C. § 60105 and § 40-2-101, C.R.S. The statutory authority permitting the Commission to enter into cooperative agreements with federal agencies, to adopt and to create rules to administer and to enforce 49 U.S.C. §§ 60101, et seq., can be found at §§ 40-2-115 and 40-7-117, C.R.S.~~
- ~~(b) — Rules 4900 through 4975 apply to, establish, and govern the:~~

- ~~(I) — Reporting by operators of gas pipeline systems of incidents, gas related events, safety-related conditions, damage statistics, notice of major projects, and annual pipeline summary data. [rules 4910 through 4929].~~
- ~~(II) — Enforcement by Staff of the Rules Regulating Gas Pipeline Safety [rules 4930 through 4949].~~
- ~~(III) — Adoption of minimum safety standards for transportation of natural gas and other gas by pipeline, specific requirements for rural gathering, procedural updates, and amendment of plans or procedures, [rules 4950 through 4959].~~
- ~~(IV) — Adoption of minimum safety standards for liquefied natural gas facilities [rules 4960 through 4969].~~
- ~~(V) — Adoption and enforcement of a drug and alcohol testing program [rule 4970].~~
- ~~(c) — Nothing in these rules shall be construed to exempt interstate or gathering pipeline operators from complying with § 9-1.5-105, C.R.S.~~

**4901. — Definitions.**

The following definitions apply to rules 4900 through 4975, except where a specific statute or rule provides otherwise or where the context otherwise indicates. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- ~~(a) — "Chief" means the program manager of the Gas Pipeline Safety Section of the Commission.~~
- ~~(b) — "Damage," when used in reference to a pipeline, means the penetration or destruction of any protective coating of an underground pipeline, the partial or complete severance of an underground pipeline, or the denting or puncturing of an underground pipeline.~~
- ~~(c) — "Damage prevention program" means an operator's written program to prevent damage to a pipeline by excavation, as defined in 49 C.F.R. § 192.614.~~
- ~~(d) — "Direct sales meter" means a meter that measures the transfer of gas to a direct sales customer purchasing gas for its own consumption.~~
- ~~(e) — "Direct sales pipeline" means a pipeline not under the jurisdiction of the Federal Energy Regulatory Commission and which runs from an intrastate or interstate transmission pipeline, a production facility, or a gathering pipeline to a direct sales meter, pressure regulator, or emergency valve, whichever is the furthest downstream.~~
- ~~(f) — "Distribution pipeline" means a pipeline other than a transmission pipeline or a gathering pipeline.~~
- ~~(g) — "Excavation" means the moving or removing of earth by means of any tools, equipment, or explosives and includes (without limitation) auguring, boring, backfilling, ditching, drilling, grading, plowing-in, pulling-in, ripping, scraping, trenching, or tunneling.~~
- ~~(h) — "Gas" means natural gas, flammable gas, toxic or corrosive gas, and petroleum gas.~~



- ~~(i) "Gathering pipeline" means a pipeline that transports gas from a current production facility to a transmission pipeline or main.~~
- ~~(j) "Hazardous facility" means a pipeline facility that, if allowed to go into operation or to remain in operation, would be hazardous to life and property.~~
- ~~(k) "Incident" means a release of gas from a pipeline covered by 49 C.F.R. § 192.1, or a release of liquefied natural gas or gas from a LNG facility, which results in any of the following:
  - ~~(I) Death or personal injury necessitating in-patient hospitalization.~~
  - ~~(II) Estimated property damage of \$50,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost.~~
  - ~~(III) An event that results in an emergency shutdown of a LNG facility.~~
  - ~~(IV) An unintentional event resulting in an estimated gas loss of three million cubic feet or more.~~
  - ~~(V) An event that is significant, in the judgment of the operator, even though it does not meet the criteria of subparagraphs (I), (II), (III), or (IV) of this paragraph.~~~~
- ~~(l) "Liquefied Natural Gas" or "LNG" means natural gas or synthetic gas which has methane (CH<sub>4</sub>) as its major constituent and which has been changed to a liquid.~~
- ~~(m) "LNG facility" means a pipeline facility that is used for liquefying natural gas or synthetic gas or for transferring, storing, or vaporizing liquefied natural gas.~~
- ~~(n) "Main" means a distribution line that serves, or is designed to serve, as a common source of supply for more than one service line.~~
- ~~(o) "Major project" means the construction of any new pipeline facility covered by 49 C.F.R. § 192.1, the repair, or upgrade of a pipeline segment, that originally is estimated to cost five hundred thousand dollars or more. As used in this rule, cost includes only the direct costs associated with the construction, repair, or upgrade.~~
- ~~(p) "Master meter system" means a pipeline system for distributing gas within a definable area (for example, a mobile home park) where the operator or owner purchases gas from an outside source for delivery through a pipeline system to an end user.~~
- ~~(q) "Municipality" means a city, town, or village in the State of Colorado.~~
- ~~(r) "Natural Gas Pipeline Act" means the federal statute found at 49 U.S.C. §§ 60101, et seq., as amended.~~
- ~~(s) "Operator" means a person who is engaged in the transportation of gas, or who has the right to bury underground pipeline, or who is both engaged in the transportation of gas and has the right to bury underground pipeline. "Operator" also may include an owner, such as a pipeline corporation.~~

- ~~(t) — "OPS" means the Office of Pipeline Safety, a unit of the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the United States Department of Transportation.~~
- ~~(u) — "Person" means an individual, firm, joint venture, partnership, corporation, association, municipality, cooperative association, or joint stock association, and includes any trustee, receiver, assignee, or personal representative thereof.~~
- ~~(v) — "Pipeline" or "pipeline system" means all parts of those physical intrastate facilities through which gas moves in transportation, including, but not limited to, pipes, valves, and other appurtenances attached to pipes, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.~~
- ~~(w) — "Pipeline facility" means new and existing intrastate pipelines, rights-of-way, and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.~~
- ~~(x) — "Production facility" means flowline and associated equipment used at a wellsite in producing, extracting, recovering, lifting, stabilizing, initial separating and/or treating, initial dehydrating, disposal, and above-ground storing of liquid hydrocarbons, associated liquids, and associated natural hydrocarbon gases. A production facility may include flowlines up to a central delivery point directly associated with a specific producing field. To be a production facility under this definition, a flowline must be used in the process of extracting hydrocarbons and associated liquids from the ground or from facilities where hydrocarbons are produced or must be used for disposal or injection in reservoir maintenance or recovery operations.~~
- ~~(y) — "Propane gas system" means a pipeline system serving ten or more structures from a single tank.~~
- ~~(z) — "Roadway" means a main public artery, highway, or interstate highway.~~
- ~~(aa) — "Service line" means a distribution line that transports gas, or is designed to transport gas, from a common source of supply to an individual customer, to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a single meter header or manifold. A service line ends at the outlet of the customer meter or at the connection to a customer's piping, whichever is furthest downstream, or at the connection to customer piping if there is no meter.~~
- ~~(bb) — "Service regulator" means the device on a service line that controls the pressure of gas delivered from a higher pressure to the pressure provided to the customer. A service regulator may serve one customer or multiple customers through a meter header or manifold.~~
- ~~(cc) — "Specified Minimum Yield Strength" or "SMYS" means:~~
- ~~(I) — For steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification.~~
- ~~(II) — For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with 49 C.F.R. § 192.107(b).~~
- ~~(dd) — "Staff" means the Staff of the Gas Pipeline Safety Section of the Commission.~~

~~(ee) "Transmission pipeline" means a pipeline, other than a gathering pipeline or distribution pipeline, that does one of the following:~~

~~(I) Transports gas from a gathering pipeline or storage facility to a distribution center, or storage facility.~~

~~(II) Operates at a hoop stress of 20 percent or more of SMYS.~~

~~(III) Transports gas within a storage field.~~

~~(IV) Is a direct sales pipeline serving a large volume customer not downstream of a distribution center, which may include, but not be limited to, factories and power plants.~~

~~(ff) "Transportation of gas" means the gathering, transmission, distribution, or storage of gas within the State of Colorado that is not subject to the jurisdiction of the Federal Energy Regulatory Commission under the Natural Gas Act.~~

**~~4902. Incorporation by Reference.~~**

~~(a) The Commission adopts by reference the minimum federal safety standards for the transportation of natural gas and other gas by pipeline of the OPS that are published in 49 C.F.R. Part 192 (October 1, 2012). This incorporation by reference does not include later amendments to, or editions of, 49 C.F.R. Part 192.~~

~~(b) The Commission adopts by reference the federal safety standards for liquefied natural gas facilities of the OPS that are published in 49 C.F.R. Part 193 (October 1, 2012). This incorporation by reference does not include later amendments to, or editions of, 49 C.F.R. Part 193.~~

~~(c) The Commission hereby adopts by reference the drug and alcohol testing program of the OPS published in 49 C.F.R. Parts 40 and 199 (October 1, 2012). This incorporation by reference does not include later amendments to, or editions of, 49 C.F.R. Parts 40 and 199.~~

~~(d) Any material incorporated by reference in this rule may be examined at the offices of the Commission, 1560 Broadway, Suite 250, Denver, Colorado 80202, during normal business hours, Monday through Friday, except when such days are state holidays. Certified copies of the incorporated standards shall be provided at cost upon request. The Director or the Director's designee will provide information regarding how the incorporated standards may be examined at any state public depository library.~~

**~~4903. Conflict.~~**

~~In the event of a conflict between the provisions of 49 C.F.R. Parts 40, 192, 193, or 199 and the rules 4900 through 4975 regarding the administrative, the enforcement, and the reporting requirements, the rules 4900 through 4975 shall apply.~~

**4904. Interpretation.**

- (a) ~~An operator may request a regulatory interpretation of any of these rules by submitting a written request to the Chief. The requestor shall include his or her return address and the specific application and rule reference with the request.~~
- (b) ~~After a request for interpretation is received, the Chief will notify the requestor of the disposition of the request and if additional information is required.~~
- (c) ~~If the request is consistent with the state pipeline safety program and is justified, the Chief will provide the Federal Administrator for Pipeline Safety a written recommendation with terms and conditions as are appropriate.~~
- (d) ~~The interpretation is effective upon approval by the Federal Administrator for Pipeline Safety or, no action is taken by the Federal Administrator for Pipeline Safety, 60 days after the receipt of the recommendations from the Chief.~~

**4905. Special Permit.**

- (a) ~~The Commission may grant a request for a special permit authorizing a variance from any of these rules in accordance with § 40-2-115, C.R.S., 49 U.S.C. § 60118(d), and the Commission's Rules of Practice and Procedure.~~
- (b) ~~Under § 40-2-115, C.R.S. and 49 U.S.C. § 60118(d) the Commission has the authority to grant special permits in emergency situations. An emergency special permit will be granted if it is in the public interest, is not inconsistent with pipeline safety, and is necessary to address an actual or impending emergency involving pipeline transportation, including an emergency caused by a natural or manmade disaster. An emergency pipeline special permit is an order by which the Commission may temporarily modify compliance with state pipeline regulations for affected pipeline owners or operators and the Commission may waive compliance with a safety regulation if, after receiving notice, the OPS concurs in the action.~~
  - (I) ~~The Commission will determine on a case-by-case basis what duration is necessary to address the emergency. However, as required by statute, no emergency special permit may be issued for a period of more than 60 days. Each emergency special permit will automatically expire on the date stated on the permit.~~
  - (II) ~~Each request should include the following information:~~
    - (A) ~~Name of requestor and indication of whether requestor is an owner or operator;~~
    - (B) ~~Duration of the emergency special permit;~~
    - (C) ~~Specific regulations from which the owner or operator seeks relief;~~
    - (D) ~~An explanation of the actual or impending emergency;~~
    - (E) ~~Specific reasons the special permit is necessary (e.g., lack of accessibility, damaged equipment, gas supply or temporary by-pass);~~

- ~~(F) — A description of the pipeline for which special permit is sought, including:
    - ~~(i) — the mileage or footage of pipeline to be covered and the counties in which it is located;~~
    - ~~(ii) — the year the pipeline was installed;~~
    - ~~(iii) — all pipeline facilities such as pump and compressor stations that this permit will affect, and;~~
    - ~~(iv) — the material, thickness, diameter and operating pressure of the pipeline.~~~~
  - ~~(G) — A statement indicating whether and how operating the pipeline pursuant to an emergency special permit is in the public interest (e.g., continuity of service, service restoration);~~
  - ~~(H) — Proposed alternatives to compliance with the regulation (e.g., additional inspections and tests, shortened reassessment intervals);~~
  - ~~(I) — Measures to be taken after the emergency situation or permit expires whichever comes first to confirm long-term operational reliability of the facility, and;~~
  - ~~(J) — A certification that operation of the owner or operator's pipeline under the requested emergency special permit would not be inconsistent with pipeline safety.~~
- ~~(c) — An operator may propose to deviate from the standards adopted by reference to part 192 and alter the frequency of periodic inspections and tests on the basis of an engineering analysis and risk assessment.~~
- ~~(I) — An alternative frequency of inspections and tests required under part 192 will be granted if it is not inconsistent with pipeline safety. For intrastate facilities, an operator must submit its proposal to the Chief at least 120 days before the requested effective date. After receiving notice, the Chief will confer with the OPS on the action requested by the operator. The Chief may accept the proposal, with or without conditions and limitations, on a showing that the operator's proposal, which includes the adjusted interval, will provide an equal or greater overall level of safety.~~
  - ~~(II) — An operator may implement an approved reduction in the frequency of a periodic inspection or test only where the operator has developed and implemented an integrity management program that provides an equal or improved overall level of safety despite the reduced frequency of periodic inspections.~~
  - ~~(III) — Each request must include the following information:
    - ~~(A) — Name of the owner or operator;~~
    - ~~(B) — Duration of the deviation proposal;~~~~

- ~~(C) — Specific regulations from which the owner or operator seeks relief;~~
- ~~(D) — A description of the pipeline for which the deviation is sought, including:
  - ~~(i) — the mileage or footage of pipeline to be covered and the counties in which it is located;~~
  - ~~(ii) — the year the pipeline was installed;~~
  - ~~(iii) — all pipeline facilities that this request will affect, and;~~
  - ~~(iv) — the material, thickness, diameter and operating pressure of the pipeline.~~~~
- ~~(E) — Proposed alternatives to compliance with the regulation (e.g., additional inspections and tests, shortened reassessment intervals); and~~
- ~~(F) — A certification that operation of the owner or operator's pipeline under the requested alternative frequency of periodic inspections and tests would not be inconsistent with pipeline safety.~~

~~(d) — Grants and denials. If the Chief determines that the permit to deviate complies with the requirements of this rule and that the deviation from the regulation or standard is not inconsistent with pipeline safety, the Chief may grant the request, in whole or in part, on a temporary or permanent basis. Conditions may be imposed on the request if the Chief concludes that they are necessary to assure safety, or are otherwise in the public interest. If the Chief determines that the application does not comply with the requirements of this rule or that a deviation is not justified, the request for deviation will be denied. Whenever the Chief grants or denies a request for deviation, the notice of the decision will be provided to the applicant. All special permits will be posted on the PUC website at <http://cdn.colorado.gov/cs/Satellite/DORA-PUC/CBON/DORA/1251632608618>~~

#### **4906. — Alert Bulletins.**

~~An alert or advisory bulletin may be disseminated to an operator based on recommendations from the National Transportation Safety Board, the OPS, or as a result of a situation which may pose a threat to pipeline systems or the public. After receiving information concerning an alert or advisory bulletin, an operator shall take appropriate action to review and to revise its design, installation, and/or its operating and maintenance procedures.~~

#### **4907. — 4909. — [Reserved].**

#### **Filing Incident, Safety-Related Condition, Major Project, Damage and Locate Summary, and Annual Reports**

#### **4910. — Submission of Reports.**

~~(a) — An operator must submit reports required by these rules, except notices of major projects, and of pipeline damage and locate summary information, electronically to the OPS at <http://opsweb.phmsa.dot.gov>.~~

~~(b) — A copy of each report submitted to the OPS shall be furnished via U.S. mail, emailed to the gas pipeline safety contact found on the Commission's Pipeline Safety Website in a .pdf searchable document, or by a facsimile to (303) 894-2065. In lieu of sending a copy of an OPS report, operators may supply operator identification number and PIN number information to permit Staff access to the OPS reporting site.~~

**4911. — Telephonic Reports.**

~~(a) — As soon as possible after discovery, but generally not to exceed two hours after discovery, an operator must telephonically report any incident to the Staff at (303) 894-2854 and to the National Response Center of the U.S. Department of Transportation at (800) 424-8802 or electronically at <http://www.nrc.uscg.mil>.~~

~~(b) — The operator of a pipeline, including a gathering pipeline in a class 1, 2, 3, or 4 area, of a LNG system, of a master meter system, or of a propane system, must telephonically report to the Staff at (303) 894-2854, within two hours after discovery, any of the following events:~~

~~(I) — A gas leak that occurs on the pipeline, the LNG system, the master meter system, or the propane system and that results in the evacuation of 50 or more people from a normally occupied building or property.~~

~~(II) — A gas leak that occurs on the pipeline, the LNG system, the master meter system, or the propane system and that results in the closure of a roadway or railroad.~~

~~(c) — A telephonic report made pursuant to paragraphs (a) or (b) of this rule must include the following information:~~

~~(I) — The name and telephone number of the operator and the contact.~~

~~(II) — The location of the incident or event.~~

~~(III) — The date and time of the incident or event.~~

~~(IV) — The number of fatalities and personal injuries, if any.~~

~~(V) — All other significant facts that are known by the person making the report that are relevant to the cause of the incident or event and the extent of the damage.~~

~~(VI) — The National Response Center control number, if known.~~

**4912. — Written Reports by Operators of Distribution Systems.**

~~(a) — Except as provided in paragraph (c) of this rule, an operator of a distribution pipeline system must submit OPS Form PHMSA F 7100.1 Incident Report: Gas Distribution System in the manner required by rule 4910 as soon as possible after the detection of an incident, but not later than 30 days after detection.~~

~~(b) — After submitting an incident report pursuant to paragraph (a) of this rule, an operator must submit a supplemental report in the manner required by rule 4910 if the operator obtains additional,~~

~~relevant information. The operator must submit the supplemental report as soon as possible, but not more than 60 days after obtaining the additional information.~~

- ~~(c) — An operator of a master meter system or a propane gas system is not required to file an incident report.~~
- ~~(d) — Except as provided in paragraph (e) of this rule, an operator of a distribution pipeline system must submit an annual report for its intrastate pipeline system on OPS Form PHMSA F 7100.1-4 Distribution system: Annual Report in the manner required by rule 4910. This report shall be submitted annually by March 15 for the preceding calendar year.~~
- ~~(e) — An operator of a propane gas system which serves fewer than 100 customers from a single source, a master meter system, or a LNG facility is not required to submit an annual report.~~

#### ~~4913. — Written Reports by Operators of Transmission and Gathering Systems.~~

- ~~(a) — An operator of a transmission pipeline system or an OPS regulated type A or type B gathering pipeline segment as defined in 49 C.F.R. Part 192 must submit OPS Form PHMSA F 7100.2 Transmission and Gathering system: Incident Report in the manner required by rule 4910 as soon as possible after the detection of an incident, but not later than 30 days after detection.~~
- ~~(b) — After submitting an incident report pursuant to paragraph (a) of this rule, an operator must submit a supplemental report in the manner required by rule 4910 if the operator obtains additional, relevant information. The operator shall submit the supplemental report as soon as possible, but not more than 60 days after obtaining the additional information. The supplemental report shall reference the original report by date and subject.~~
- ~~(c) — An operator of a transmission pipeline system or an OPS regulated type A or type B gathering pipeline segment(s) as defined in 49 C.F.R. Part 192 must submit OPS Form PHMSA F 7100.2.1 Transmission and Gathering system: Annual Report information in the manner required by rule 4910. This report shall be submitted annually by March 15 for the preceding calendar year.~~

#### ~~4914. — Reports of Safety-Related Conditions.~~

- ~~(a) — Except as provided in paragraph (d) of this rule, an operator must submit a safety-related condition report in the manner required by rule 4910 on the existence of any of the following safety-related conditions with respect to a regulated pipeline in service:
  - ~~(I) — In the case of a pipeline that operates at a hoop stress of 20 percent or more of its SMYS, (a) general corrosion that has reduced the wall thickness to less than that required for the maximum allowable operating pressure and (b) localized corrosion pitting to a degree where leakage might result.~~
  - ~~(II) — Unintended movement or abnormal loading by naturally occurring environmental causes (for example, earthquakes, landslides, or floods) that impairs the serviceability or integrity of a pipeline.~~~~



- ~~(III) — Any crack or other material defect that impairs the structural integrity or reliability of a LNG facility that contains, controls, or processes gas or LNG.~~
- ~~(IV) — Any material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop stress of 20 percent or more of its SMYS.~~
- ~~(V) — Any malfunction or operating error that causes the pressure of a pipeline or LNG facility that contains or processes gas or LNG to rise above its maximum allowable operating pressure (or working pressure for LNG facilities) plus the build-up allowed for operation of pressure limiting or control devices.~~
- ~~(VI) — A leak in a pipeline or LNG facility that contains or processes gas or LNG that constitutes an emergency.~~
- ~~(VII) — Inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of a LNG storage tank.~~
- ~~(VIII) — Any safety related condition that could lead to an imminent hazard and that causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent or more reduction in operating pressure or shutdown of operation of a pipeline or a LNG facility that contains or processes gas or LNG.~~
- ~~(b) — A report of a safety-related condition must be submitted in the manner required by rule 4910, within five business days (not including Saturday, Sunday, or federal or State holidays) after the day on which the operator or its representative first determines that a safety-related condition exists. The report shall not be submitted later than ten business days after the day an operator or its representative discovers the condition. Separate conditions may be reported in a single report if they are closely related.~~
- ~~(c) — The report shall be headed "Safety-Related Condition Report" and must provide the following information:
  - ~~(I) — Name and principal address of operator.~~
  - ~~(II) — Date of report.~~
  - ~~(III) — Name, job title, and business telephone number of the person submitting the report.~~
  - ~~(IV) — Name, job title, and business telephone number of the person who determined that the condition exists.~~
  - ~~(V) — Date the condition was discovered and, if different, date condition was first determined to exist.~~
  - ~~(VI) — Location of the condition. This requires identification of the town, city, or county in which the condition exists and, as appropriate, the nearest street address, milepost, or landmark; and the name of pipeline.~~~~

- ~~(VII) — Description of the condition, of the circumstances leading to its discovery, of any significant effects the condition has on safety, and of the type of gas transported or stored.~~
  - ~~(VIII) — Description of the corrective action taken (including reduction of pressure or shutdown) before the report was submitted.~~
  - ~~(IX) — Description of any planned future follow-up or corrective action, including the anticipated schedule for starting and concluding such action.~~
- ~~(d) — A written report need not be made for any safety-related condition that:~~
- ~~(I) — Exists on a regulated gathering system as defined by 49 C.F.R. Part 192 and where a MAOP produces a hoop stress less than 20 percent of SMYS, a master meter system, a propane gas system, or a customer-owned service line.~~
  - ~~(II) — Is an event or results in an event which occurs before a permanent repair or replacement pertaining to an already reported incident can be completed.~~
  - ~~(III) — Exists on a pipeline (other than a LNG pipeline) that is more than 220 yards from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad or roadway.~~
  - ~~(IV) — Is corrected by permanent repair or replacement in accordance with applicable safety standards within five business days of the day on which the operator first determines that the condition exists, but not later than ten business days after an operator or its representative discovers the condition. This subparagraph does not apply to localized corrosion pitting on an effectively coated and cathodically protected pipeline.~~

**~~4915. — Reporting of Pipeline Damage and of Locate Information.~~**

- ~~(a) — An operator of a local distribution company or municipal operated system must file with the Commission information concerning general pipeline damage and pipeline locate information annually, by March 15. This report applies to damage to underground pipelines, excluding any damage to electrically conductive tracer wire.~~
- ~~(b) — Each report shall include the following pipeline information:~~
  - ~~(I) — Total number of facility locates transmitted from the Utility Notification Center of Colorado (UNGC);~~
  - ~~(II) — Total number of excavation related damages to mains;~~
  - ~~(III) — Total number of excavation related damages to services;~~
  - ~~(IV) — Total number of excavation related damages to transmission pipelines;~~
  - ~~(V) — Total number of excavation damage due to excavation practice being insufficient;~~

- ~~(VI) — Total number of excavation damage due to operator locator practice being insufficient;~~
- ~~(VII) — Total number of excavation damage due to contract locator practice being insufficient;~~
- ~~(VIII) — Total number of excavation damage due to no facility locate requested; and~~
- ~~(IX) — Total number of excavation damage due to other reasons. A root cause explanation must be included with each reported damage under this category.~~

~~(c) — Pipeline operators are required to be Tier 1 members and report underground facility damages to the Utility Notification Center of Colorado (UNCC-Colorado 811) “Colorado Damage Reporting Tool DIRT” at <https://www.damagereporting.org/uncc>.~~

~~(d) — Additional specific damage information may be requested under paragraph 4932(c).~~

**4916. — Filing Notices of Major Project.**

~~(a) — Written notice of a major project must be submitted to the Staff not later than 20 business days prior to the scheduled commencement date of the project, if practicable.~~

~~(b) — The notice shall contain the following information:~~

~~(I) — The type of construction or repair.~~

~~(II) — The date of commencement.~~

~~(III) — The estimated period of construction or repair.~~

~~(IV) — Pipeline design specifications, and the test medium (for example, gas, inert gas, water).~~

~~(V) — The location of the construction or repair.~~

~~(VI) — The estimated cost of the construction or repair project.~~

**4917. — 4929. — [Reserved].**

**Procedure For Enforcement**

**4930. — Service.**

~~(a) — An order, notice, complaint or other document required to be served under these rules shall be served personally or by registered or certified mail.~~

~~(b) — Service upon an operator’s authorized representative or agent constitutes service upon that operator.~~

~~(c) — Service by registered or certified mail is complete upon mailing. An official U.S. Postal Service receipt evidencing a registered or certified mailing constitutes prima facie evidence of service.~~

**4931. ~~Subpoenas.~~**

- ~~(a) The Commission, an Administrative Law Judge, or the Director may issue a subpoena in accordance with rule 1406.~~
- ~~(b) Rule 45 of the Colorado Rules of Civil Procedure, except as provided in rule 1406 and §§ 40-6-102 and 103, C.R.S., shall govern a subpoena issued under this rule.~~
- ~~(c) A subpoena issued under this rule may be enforced in the district court, as provided by § 40-6-103(2), C.R.S.~~

**4932. ~~Inspections and Testing.~~**

- ~~(a) As authorized by the Chief, Staff may enter upon, to inspect, and to examine, at reasonable times, an operator's right of way or easement, new and existing piping, valves, and other above ground appurtenances attached to pipes, or, upon request of the OPS, an interstate pipeline to determine compliance with 49 U.S.C. §§ 60101 et seq., with these rules, with Commission orders, or with orders issued pursuant to these rules. If requested, Staff shall present Commission credentials at the time of the inspection.~~
- ~~(b) Staff may require testing of an operator's pipeline. Staff shall make every effort to negotiate with the operator of the pipeline a mutually acceptable testing plan before performing such tests.~~
- ~~(c) If information is needed, the Chief may send the operator a request for specific information to be answered within 45 days after receipt of the request.~~
- ~~(d) When information obtained from an inspection, testing, a request for specific information, or other sources indicates that enforcement action is warranted, the Chief may do one of the following:
  - ~~(I) Serve on the operator a Warning Letter pursuant to rule 4933 or a Notice of Probable Violation pursuant to rule 4934.~~
  - ~~(II) File a formal complaint with the Commission requesting a Hazardous Facilities Order pursuant to rule 4940.~~~~

**4933. ~~Warning Letters.~~**

- ~~(a) If the Chief believes that an operator has committed a probable violation of 49 U.S.C. §§ 60101 et seq., of these rules, of a Commission order, or of an order issued pursuant to these rules, the Chief may serve a warning letter on the operator advising the operator of the probable violation and advising the operator to correct the probable violation or be subject to an enforcement action under these rules.~~
- ~~(b) Within 30 days after receipt of a warning letter, an operator shall respond to the Chief by submitting a written explanation, information, or other material in answer to the allegations contained in the warning letter.~~

**4934. Notices of Probable Violation.**

- (a) ~~If the Chief believes that an operator has committed a probable violation of 49 U.S.C. §§ 60101, et seq., of these rules, of a Commission order, or of an order issued pursuant to these rules, the Chief may commence an enforcement proceeding against an operator by serving the operator with a notice of probable violation charging such person with a probable violation of 49 U.S.C. §§ 60101, et seq., of these rules, of a Commission order, or of an order issued pursuant to these rules.~~
- (b) ~~A notice of probable violation served pursuant to paragraph (a) of this rule shall include:~~
- ~~(I) A statement of the facts upon which the notice of probable violation is based.~~
  - ~~(II) A statement of the law, rule(s), or order(s) that the operator is alleged to have violated.~~
  - ~~(III) A statement of the response options available to the operator.~~
  - ~~(IV) Either or both of the following:
    - ~~(A) A proposed civil penalty, including the maximum amount of a penalty for which the operator may be liable, pursuant to rule 4936.~~
    - ~~(B) A proposed compliance directive pursuant to rule 4937.~~~~

**4935. Response Options to Amendment and to Notice of Probable Violation.**

- (a) ~~Within 30 days after receipt of an amendment issued pursuant to rule 4954 or of a notice of probable violation issued pursuant to rule 4934, an operator shall respond in writing to the Chief in one or more of the following ways:~~
- ~~(I) The operator may pay the proposed civil penalty in full.~~
  - ~~(II) The operator may agree to the proposed compliance directive.~~
  - ~~(III) The operator may submit an offer in compromise of the proposed civil penalty. The operator may make an offer in compromise by submitting a check or money order for the amount offered. The Chief will consider the offer in compromise in light of the criteria established in § 40-7-117(2), C.R.S., and of other relevant factors. If the offer in compromise is accepted by the Chief, the operator will be notified in writing that the acceptance is in full settlement of the proposed civil penalty. If an offer in compromise is rejected by the Chief, the check or money order will be returned to the operator with a written notification. Within ten days after receipt of a notice of rejection, the operator shall respond to the Chief in one or more of the ways provided in paragraph (a) of this rule.~~
  - ~~(IV) The operator may request the execution of a consent stipulation pursuant to rule 4939.~~
  - ~~(V) The operator may submit a written explanation, information, or other material in response to the allegations contained in the notice of probable violation; in objection to the proposed compliance directive; or in mitigation of the proposed civil penalty.~~

~~(VI) — The operator may request a hearing. If an operator requests a hearing, the Chief may amend the notice of probable violation at any time up to 30 days prior to the first day of hearing. After that time, a notice of probable violation may be amended only in accordance with the Commission's Rules Regulating Practice and Procedure.~~

~~(b) — If the operator fails to respond as provided in this rule, the notice of probable violation shall be set for hearing.~~

~~(c) — If the operator fails to respond as provided in this rule, the notice of amendment shall be set for hearing.~~

**4936. — Civil Penalties.**

~~(a) — As provided in §§ 40-2-115(2) and 40-7-117, C.R.S., an operator who violates 49 U.S.C. §§ 60101, et seq., these rules, an order of the Commission, or an order issued under these rules shall be subject to a civil penalty not to exceed \$100,000 per violation. Each day of a continuing violation shall constitute a separate violation. In the case of a group or series of related violations, the aggregate amount of such penalties shall not exceed \$1,000,000.~~

~~(b) — No operator shall be subject to a second or additional civil penalty for violations based on the same act.~~

**4937. — Compliance Directives.**

~~When the Chief serves a notice of probable violation on an operator, the Chief may include in that notice a compliance directive requiring the operator to take remedial action.~~

**4938. — Hearing on Notice of Probable Violation.**

~~(a) — If it requests a hearing in response to a notice of probable violation, an operator shall include in its request a written statement of the issues that it intends to raise at the hearing. The issues may include new information. Failure of the operator to specify an issue shall result in a waiver of that issue at the hearing unless, for good cause shown, the Commission permits the issue to be raised.~~

~~(b) — The hearing shall be held, and an order issued, in accordance with the Commission's Rules Regulating Practice and Procedure and Article 6 of Title 40, C.R.S.~~

~~(c) — The Commission may include in its order a civil penalty. If it includes a civil penalty, the order shall specify the amount of the penalty and the procedures for paying the penalty. The Commission may order a civil penalty only after considering the following:~~

~~(I) — The nature, circumstances, and gravity of the violation.~~

~~(II) — The operator's degree of culpability and its history of prior violations.~~

~~(III) — Any good faith efforts by the operator to remedy the violation or to prevent future similar violations.~~

- ~~(IV) — The size of the operator's business.~~
- ~~(V) — The operator's ability to pay the civil penalty and to continue in business after doing so.~~
- ~~(VI) — Any other matter in aggravation or in mitigation.~~
- ~~(d) — The Commission may include in its order a compliance directive. If the order includes a compliance directive, the order shall specify the actions to be taken by the operator and the time by which such actions must be completed.~~
- ~~(e) — The Commission may include in its order any other remedial action, requirement, or directive to ensure the public safety.~~

~~**4939. — Consent Stipulations.**~~

- ~~(a) — At any time before the issuance of a decision by the Commission, the Chief and the operator may agree to dispose of the matter by a consent stipulation, which shall be submitted to the Commission for approval or rejection.~~
- ~~(b) — A consent stipulation executed under this rule shall include the following:
  - ~~(I) — An admission by the operator of all jurisdictional facts.~~
  - ~~(II) — An express waiver by the operator of further procedural steps, including (without limitation) its right to a hearing; its right to seek judicial review or otherwise to challenge or to contest the validity of the consent stipulation; and its right to seek judicial review of the Commission order accepting the consent stipulation.~~
  - ~~(III) — An acknowledgment by the operator that the notice of probable violation may be used to construe the terms of the consent stipulation.~~
  - ~~(IV) — A statement of the actions which the operator will take and the date by which such actions shall be completed.~~~~
- ~~(c) — As appropriate, a consent stipulation executed under this rule may include a civil penalty.~~

~~**4940. — Hazardous Facilities Orders.**~~

- ~~(a) — After an inspection and/or a test, if the Chief is of the opinion that a pipeline facility or a LNG facility may be a hazardous facility, Staff may file a formal complaint with the Commission against the operator of the pipeline facility or the LNG facility. The complaint shall allege facts sufficient to establish the existence of a hazardous facility and to support a hazardous facility order. In an appropriate case and with the complaint, Staff may file a motion for an order pursuant to paragraph (j) of this rule.~~
- ~~(b) — A formal complaint by Staff shall be issued, and hearing shall be conducted, in accordance with the Commission's Rules Regulating Practice and Procedure and Article 6 of Title 40, C.R.S.~~

- ~~(c) — Except as provided in paragraph (j) of this rule, if the Commission finds, after hearing, that a pipeline facility or a LNG facility is hazardous to life or property, the Commission shall issue an order directing the operator to take corrective action. Corrective action may include, without limitation, suspension or restriction of the use of the pipeline facility or LNG facility, physical inspection, testing, repair, or replacement.~~
- ~~(d) — A pipeline facility or a LNG facility may be found to be a hazardous facility if the pipeline facility or a LNG facility has been constructed or operated with any equipment, material, or technique that is hazardous to life or property.~~
- ~~(e) — In making a determination that a pipeline facility or a LNG facility is hazardous to life or property, the following shall be considered, as appropriate:
  - ~~(I) — The characteristics of the pipe used in the pipeline facility or the LNG facility involved, including (without limitation) its age; manufacturer; physical properties, including its resistance to corrosion and deterioration; and the method of its manufacture, construction, or assembly.~~
  - ~~(II) — The nature of the gas transported by the pipeline facility or the LNG facility, including its corrosive and deteriorative qualities; the sequence in which the gas is transported; and the pressure required for transportation of the gas.~~
  - ~~(III) — The characteristics of the areas in which the pipeline facility or the LNG facility is located, in particular the climatic and geologic conditions (including soil characteristics) associated with the areas, the population, the population density, and the growth patterns of the areas.~~
  - ~~(IV) — Any recommendation of the National Transportation Safety Board issued in connection with any investigation conducted by that Board.~~
  - ~~(V) — Such other factors as may be relevant.~~~~
- ~~(f) — A Commission decision finding that a pipeline facility or a LNG facility is a hazardous facility shall contain the following:
  - ~~(I) — Findings of fact that form the basis for the conclusion that the pipeline facility or the LNG facility is hazardous to life or property.~~
  - ~~(II) — Conclusion that the pipeline facility or the LNG facility is a hazardous facility.~~
  - ~~(III) — Legal basis for the decision and order.~~
  - ~~(IV) — Description of the corrective action required of the operator.~~
  - ~~(V) — The date by which the operator shall complete the ordered corrective action.~~~~
- ~~(g) — The Commission shall dismiss the complaint if it determines that the pipeline facility or the LNG facility is not hazardous to life or property.~~



- ~~(h) — Upon a showing that the ordered corrective action has been completed and has eliminated the condition(s) which made a pipeline facility or a LNG facility hazardous to life or to property, the Commission shall issue an order of satisfaction. Prior to issuing an order of satisfaction, the Commission may hold a hearing to determine whether the operator has completed the corrective action and whether the corrective action has eliminated the condition(s) which made the pipeline facility or the LNG facility hazardous to life or property. The order of satisfaction shall be issued in the complaint docket in which the hazardous facilities order was entered.~~
- ~~(i) — Following issuance of an order of satisfaction, the Chief may issue a notice of probable violation pursuant to rule 4934.~~
- ~~(j) — If the Commission determines that the delay inherent in holding a hearing may result in, and significantly increases the likelihood of, serious harm to life or property, the Commission may issue a summary hazardous facilities order before holding a hearing. The provisions of paragraph (b) of this rule shall apply to a hearing held pursuant to this paragraph. The purpose of a hearing held pursuant to this paragraph is to determine whether the summary hazardous facilities order should remain in effect, should be amended, or should be rescinded. The summary hazardous facilities order shall include the following:~~
- ~~(I) — The findings which support the determination that a summary hazardous facilities order is appropriate.~~
- ~~(II) — The corrective or remedial actions required of the operator.~~
- ~~(III) — A statement informing the operator of its right to a hearing, upon request, as soon as practicable after issuance of the order.~~

**~~4941. — Injunctive Action.~~**

~~Whenever it appears to the Commission that an operator has engaged in, is engaging in, or is about to engage in any act or practice which constitutes a violation of 49 U.S.C. §§ 60101, et seq., these rules, an order of the Commission, or an order issued under these rules, the Commission may request that the Attorney General bring an action in a district court for an injunctive or other relief as provided in Article 7 of Title 40, C.R.S.~~

**~~4942. – 4949. — [Reserved].~~**

**Safety Standards for Gas Transportation by Pipeline and Gas Pipeline Systems**

**~~4950. — Compliance.~~**

~~An operator shall comply with these rules and the minimum safety standards for the transportation of natural gas and other gas by pipeline which are incorporated by reference in rule 4902(a).~~

**~~4951. — Conversion to Service.~~**

~~A pipeline previously used in service not subject to 49 C.F.R. Part 192 qualifies for service subject to 49 C.F.R. Part 192 if the operator prepares and follows a written procedure addressing the requirements of~~

~~49 C.F.R. § 192.14. The operator shall make its written procedures and applicable records available to Staff upon request.~~

**~~4952. Gathering Pipeline.~~**

- ~~(a) In addition to 49 C.F.R. § 192.9, all gathering pipeline operators must report underground facility damages to the Utility Notification Center of Colorado (UNCC-Colorado 811) “Colorado Damage Reporting Tool-DIRT” at <https://www.damagereporting.org/uncc>.~~
- ~~(b) Type A regulated gathering lines: An operator of metallic gathering lines where the MAOP produces a hoop stress of 20 percent or more of SMYS or non-metallic lines where the MAOP is more than 125 psig and located in a class 2, 3, or 4 location as defined in part § 192.5 shall follow the requirements of part 192 applicable to transmission pipelines, except the requirements in §192.150 and in subpart O of §192. However, an operator of a Type A gathering pipeline located in a class 2 location may demonstrate compliance with subpart N by describing the processes it uses to determine the qualifications of persons performing operation and maintenance tasks.~~
- ~~(c) Type B regulated gathering lines: An operator of metallic gathering lines where the MAOP produces a hoop stress less than 20 percent of SMYS or non-metallic lines and the MAOP is at 125 psig or less, and located in a class 2, 3, or 4 location as determined by using one of three methods found in part § 192.8, must comply with the following requirements:~~
- ~~(I) If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of part 192 applicable to transmission lines;~~
  - ~~(II) If the pipeline is metallic, control corrosion according to requirements of subpart I of part 192 applicable to transmission lines;~~
  - ~~(III) Carry out a damage prevention program under § 192.614;~~
  - ~~(IV) Establish a public education program under § 192.616;~~
  - ~~(IV) Establish the MAOP of the line under § 192.619;~~
  - ~~(IV) Install and maintain line markers according to the requirements for transmission lines in § 192.707;~~
  - ~~(IV) Carry out a leakage control program according to § 192.723(b);~~
  - ~~(IV) At a minimum, prepare a Procedural Manual addressing the above maintenance and operations items, and;~~
  - ~~(IV) Report any incident, or events as described in 4911(b), to Staff. Any hazardous leakage or conditions which may lead to a hazardous facility order shall be promptly repaired and documented.~~

- ~~(d) Type C gathering lines: An operator of gathering lines located in a class 1 location as defined in § 192.5 or type B gathering lines located in class 2 areas that the operator determines does not meet Area 2 dwelling density in §192.8, must comply with the following requirements:~~
- ~~(I) Telephonically report any incident, or events as described in 4911(b) to Staff. Any hazardous leakage or conditions which may lead to a safety threat to the public shall be promptly repaired and documented;~~
  - ~~(II) Tier 1 Member at the Utility Notification Center of Colorado if the pipeline system is located in any public road or railroad right-of-way, and;~~
  - ~~(III) Install and maintain pipeline markers at each crossing of a public road or railroad right-of-way, and labeled according to § 192.707(d).~~

#### ~~4953. Procedural Updates.~~

~~As soon after the end of an incident, a safety-related condition, or an abnormal operating condition as defined in 49 C.F.R. § 192.803 as possible, each operator shall investigate, and shall make applicable changes to the operator qualification program, and the written procedural manual(s) used for conducting operations, for maintenance, and for emergencies. At a minimum, the operator shall review (and update, if necessary) applicable plans or procedural manual(s) at intervals not exceeding 15 months, but at least once each calendar year.~~

#### ~~4954. Amendment of Plans or Procedures.~~

- ~~(a) If the Chief determines that an operator's plans or procedures required by rules 4900 through 4975 are inadequate to assure safe operation of a pipeline facility or a LNG facility, the Chief shall issue a notice of amendment to initiate a proceeding to determine whether the plans or procedures are inadequate. The notice of amendment shall:~~
- ~~(I) Provide an opportunity for a hearing pursuant to rule 4935.~~
  - ~~(II) Specify the alleged inadequacies and the proposed action for revision of the plans or procedures.~~
  - ~~(III) Allow the operator 30 days after receipt of the notice to submit written comments pursuant to rule 4935 or to request a hearing.~~
- ~~(b) In determining the adequacy of an operator's plans or procedures, the Chief shall consider the following:~~
- ~~(I) Relevant available pipeline safety data.~~
  - ~~(II) Whether the plans or procedures are appropriate for the particular type of pipeline transportation or facility and for the location of the facility.~~
  - ~~(III) The reasonableness of the plans or procedures.~~
  - ~~(IV) The extent to which the plans or procedures contribute to public safety.~~

~~(c) — Amendment of an operator’s plans or procedures as prescribed in paragraph (a) of this rule is in addition to, and may be used in conjunction with, other enforcement action.~~

~~4955. – 4959. — [Reserved].~~

**Safety Standards for Liquefied Natural Gas Facilities**

~~4960. — Compliance.~~

~~An operator shall comply with the safety standards for liquefied natural gas facilities which are incorporated by reference in rule 4902(b).~~

~~4961. – 4969. — [Reserved].~~

**Drug and Alcohol Testing**

~~4970. — Compliance.~~

~~An operator shall comply with the drug and alcohol testing program which is incorporated by reference in rule 4902(c) applicable to 49 C.F.R. Part 192 pipeline systems.~~

~~4971. – 4975. — [Reserved].~~

**4976. Regulated Gas Utility Rule Violations, Civil Enforcement, and Civil Penalties.**

An admission to or Commission adjudication for liability for an intentional violation of the following may result in the assessment of a civil penalty of up to \$2,000.00 per offense. Fines shall accumulate up to, but shall not exceed, the applicable statutory limits set in § 40-7-113.5, C.R.S.

Citation	Description	Maximum Penalty Per Violation
	Articles 1-7 of Title 40, C.R.S.	\$2000
	Commission Order	\$2000
Rule 4005	Records and Record Retention	\$2000
Rule 4027(a)	Collection and Use of Customer Data	\$1000
Rule 4027(b),	Disclosure of Customer Data	\$2000
Rule 4027(c)	Tariff	\$1000
Rule 4027(d)	Disclosure of Customer Data	\$1000

Rule 4028(a)	Customer Notice	\$1000
Rule 4029(a),(b)	Consent Form	\$1000
Rule 4030(a)	Disclosure of Customer Data	\$2000
Rule 4030(b)	Records	\$1000
Rule 4031(a)	Disclosure of Customer Data	\$2000
Rule 4031(b)	Records	\$1000
Rule 4032(a)	Disclosure of Customer Data	\$2000
Rules 4032(c) and (d)	Consent and Records	\$1000
Rule 4033(a)	Disclosure of Aggregated Data	\$2000
Rule 4033(d)	Tariff	\$1000
Rule 4100(a)	Obtaining a Certificate of Public Convenience and Necessity for a Franchise	\$2000
Rule 4101(a)	Obtaining a Certificate of Public Convenience and Necessity or Letter of Registration to operate in a service territory	\$2000
Rule 4102(a)	Obtaining a Certificate of Public Convenience and Necessity for facilities	\$2000
Rule 4103(a), (c), (d)	Amending a Certificate of Public Necessity for changes in service territory or facilities	\$2000
Rule 4108(a), (c)	Keeping a Current Tariff on File with the Commission	\$2000
Rule 4109	Filing a New or Changed Tariff with the Commission	\$2000
Rule 4110(b),(c)	Filing an Advice Letter to Implement a Tariff Change	\$2000
Rule 4200	Construction, Installation, Maintenance and Operation of Facilities in Compliance with Accepted Engineering and Industry Standards	\$2000

Rule 4208	Anticompetitive Conduct and Unacceptable Practices	\$2000
Rule 4210	Line Extensions	\$2000
Rule 4303	Meter Testing	\$2000
Rule 4306	Record Retention of Tests and Meters	\$2000
Rule 4309	Provision of Written Documentation of Readings and Identification of When Meters Will be Read	\$2000
Rule 4401	Billing Information, Procedures, and Requirements	\$2000
Rule 4754(a)-(e)	Annual DSM Report and Application for Bonus and Bonus Calculation	\$2000
Rule 4803(c)	Master Meter Exemption Requirements	\$2000
Rule 4004(b)-(f)	Disputes and Informal Complaints	\$1000
Rule 4202	Maintaining Heating Value, Purity and Pressure Standards	\$1000
Rule 4203(a)-(f)	Trouble Report Response, Interruptions and Curtailments of Service	\$1000
Rule 4405	Provision of Service, Rate, and Usage Information to Customers	\$1000
Rule 4406	Provision of Gas Cost Component Information to Customers	\$1000
Rule 4603(a),(d)	Gas Cost Adjustments	\$1000
Rule 4605(a),(b),(e),(f)	Gas Purchase Plans	\$1000
Rule 4607(a)	Gas Purchase Reports and Prudence Reviews	\$1000
Rule 4403(a)-(q)	Applications for Service, Customer Deposits, and Third Party Guarantees	\$500
Rule 4006	Annual Reporting Requirements	\$100

Rule 4304	Scheduled Meter Testing	\$100
Rule 4305	Meter Testing Upon Request	\$100
Rule 4402(a),(c),(d)	Meter and Billing Error Adjustments	\$100
Rule 4404(a)-(f)	Availability of Installation Payments to Customers	\$100
Rule 4407	Discontinuance of Service	\$100
Rule 4408(a)-(g); (i)	Notice of Discontinuance of Service	\$100
Rule 4409	Restoration of Service	\$100
Rule 4411(c)(IV),(d)(I), d(II),(e)	Low-Income Energy Assistance Act	\$100

**4977. – 4999. [Reserved].**

**GLOSSARY OF ACRONYMS.**

CAAM –	Cost Allocation and Assignment Manual
CCR –	Colorado Code of Regulations
C.F.R. –	Code of Federal Regulations
CPCN -	Certificate of Public Convenience and Necessity
CRCP –	Colorado Rules of Civil Procedure
C.R.S. -	Colorado Revised Statutes
<del>EAO –</del>	<del>Energy Assistance Organization</del>
e-mail -	Electronic mail
FDC -	Fully Distributed Cost
FERC –	Federal Energy Regulatory Commission
GAAP -	Generally Accepted Accounting Principles
GCA –	Gas Cost Adjustment
GPP –	Gas Purchase Plan
GPR –	Gas Purchase Report
ITP –	Intrastate Transmission Pipeline
LDC –	Local Distribution Company
<del>LNG –</del>	<del>Liquefied Natural Gas</del>
MMO –	Master Meter Operator
<del>NGA –</del>	<del>Natural Gas Act</del>
<del>OPS –</del>	<del>Office of Pipeline Safety (Federal DOT)</del>
OCC -	Office of Consumer Counsel
<del>PHMSA -</del>	<del>Pipeline and Hazardous Materials Safety Administration</del>

<del>P &amp; P</del>	<del>Practice and Procedure</del>
<del>SMYS</del>	<del>Specified Minimum Yield Strength</del>
<del>UNCC</del>	<del>Utility Notification Center of Colorado</del>
<del>U.S.C.</del>	<del>United States Code</del>
<del>U.S. DOT</del>	<del>United States Department of Transportation</del>
USOA –	Uniform System of Accounts

**Glossary of Gas Measurement Units:**

Btu –	British Thermal Unit
MMBtu –	1,000,000 Btu (approximately one Mcf, depending on heat content of gas)
Dth –	Dekatherm or One MMBtu
Therm –	100,000 Btu (approximately one Ccf, depending on heat content of gas)
Scf -	Standard cubic feet
Ccf –	100 cubic feet (typically actual cf at meter, rather than Scf)
Mcf –	1,000 standard cubic feet
MMcf –	1,000,000 standard cubic feet
Bcf –	1,000,000,000 standard cubic feet
MMcfd –	One MMcf per day



## **COLORADO DEPARTMENT OF REGULATORY AGENCIES**

### **Public Utilities Commission**

#### **4 CODE OF COLORADO REGULATIONS (CCR) 723-4**

#### **PART 4 RULES REGULATING GAS UTILITIES**

##### **BASIS, PURPOSE, AND STATUTORY AUTHORITY.**

The basis and purpose of these rules is to set forth rules describing the service to be provided by jurisdictional gas utilities and master meter operators to their customers and describing the manner of regulation over jurisdictional gas utilities, master meter operators, and the services they provide. These rules address a wide variety of subject areas including, but not limited to, service interruption, meter testing and accuracy, safety, customer information, customer deposits, rate schedules and tariffs, discontinuance of service, master meter operations, transportation service, flexible regulation, procedures for administering the Low-Income Energy Assistance Act, gas service low-income program, cost allocation between regulated and unregulated operations, recovery of gas costs, appeals regarding local government land use decisions, and authority of the Commission to impose civil penalties on public utilities. The statutory authority for these rules can be found at §§ 29-20-108, 40-1-103.5, 40-2-108, 40-3-102, 40-3-103, 40-3-104.3, 40-3-106, 40-3-111, 40-3-114, 40-3-101, 40-4-101, 40-4-106, 40-4-108, 40-4-109, 40-5-103, 40-7-117, 40-7-113.5, 40-7-116.5; and 40-8.7-105(5), C.R.S.

##### **GENERAL PROVISIONS**

##### **4000. Scope and Applicability.**

- (a) Absent a specific statute, rule, or Commission order which provides otherwise, all rules in this Part 4 (the 4000 series) shall apply to all jurisdictional gas utilities, gas master meter operators, and to all Commission proceedings concerning gas utilities and gas master meter operators.
- (b) The scope and applicability rules regarding appeals of local government land use decisions are as stated in rule 4700.

##### **4001. Definitions.**

The following definitions apply throughout this Part 4, except where a specific rule or statute provides otherwise. In addition to the definitions here, the definitions found in the Public Utilities Law and Part 1 apply to these rules. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply. In the event of a conflict between these definitions and a definition in Part 1, these definitions shall apply.

- (a) "Affiliate" of a utility means a subsidiary of a utility, a parent corporation of a utility, a joint venture organized as a separate corporation or partnership to the extent of the individual utility's

involvement with the joint venture, a subsidiary of a parent corporation of a utility or where the utility or the parent corporation has a controlling interest over an entity.

- (b) “Aggregated data” means customer data, alone or in combination with non-customer data, resulting from processing (e.g., average of a group of customers) and/or a compilation of customer data of one or more customers from which and personal information has been removed.
- (c) "Applicant for service" means a person who applies for utility service and who either has taken no previous utility service from that utility or has not taken utility service from that utility within the most recent 30 days.
- (d) "Basis Point" means one-hundredth of a percentage point (100 basis points = 1 percent).
- (e) "Benefit of service" means the use of utility service by each person of legal age who resides at a premises to which service is delivered and who is not registered with the utility as the customer of record.
- (f) "Commission" means the Colorado Public Utilities Commission.
- (g) “Contracted agent” means any person that has contracted with a utility in compliance with rule 4030 to assist in the provision of regulated utility services (e.g., an affiliate or vendor).
- (h) "Cubic foot" means, as the context requires:
  - (I) At Local Pressure Conditions. For the purpose of measuring gas to a customer at local pressure conditions, a cubic foot is that amount of gas which occupies a volume of one cubic foot under the conditions existing in the customer’s meter as and where installed. When gas is metered at a pressure in excess of eight inches of water column gauge pressure, a suitable correction factor shall be applied to provide for measurement of gas as if delivered and metered at a pressure of six inches of water column gauge pressure. A utility may also apply appropriate factors to correct local pressure measurement to standard conditions.
  - (II) At Standard Conditions. For all other purposes, including testing gas, a standard cubic foot is that amount of gas at standard conditions which occupies a volume of one cubic foot.
- (i) "Curtailment" means the inability of a transportation customer or a sales customer to receive gas due to a shortage of gas supply.
- (j) "Customer" means any person who is currently receiving utility service. Any person who moves within a utility’s service territory and obtains utility service at a new location within 30 days shall be considered a "customer." Unless stated in a particular rule, "customer" applies to any class of customer as defined by the Commission or by utility tariff.
- (k) “Customer data” means customer specific information, excluding personal information as defined in paragraph 1004(x), that is:

- (I) collected from the gas meter by the utility and stored in its data systems;
  - (II) combined with customer-specific energy usage information on bills issued to the customer for regulated utility service when not publicly or lawfully available to the general public; or
  - (III) about the customer's participation in regulated utility programs, such as renewable energy, demand-side management, load management, or energy efficiency programs.
- (l) "Dekatherm" (Dth) means a measurement of gas commodity heat content. One Dekatherm is the energy equivalent of 1,000,000 British Thermal Units (1 MMBtu).
  - (m) "Distribution system" means the piping and associated facilities used to deliver gas to customers, excluding facilities owned by a utility that are classified on the books and records of the utility as production, storage, or transmission facilities.
  - (n) "Energy assistance organization" means the nonprofit corporation established for low-income energy assistance pursuant to § 40-8.5-104, C.R.S.
  - (o) "Gas" means natural gas; flammable gas; manufactured gas; petroleum or other hydrocarbon gases including propane; or any mixture of gases produced, transmitted, distributed, or furnished by any utility.
  - (p) "Informal complaint" means an informal complaint as defined and discussed in the Commission's Rules Regulating Practice and Procedure.
  - (q) "Interruption" means a utility's inability to provide transportation to a transportation customer, or its inability to serve a sales customer, due to constraints on the utility's pipeline system.
  - (r) "Intrastate transmission pipeline" or "ITP" means generally any person that provides gas transportation service for compensation to or for another person in the State of Colorado using transmission facilities rather than distribution facilities and is exempt from FERC jurisdiction.
  - (s) "Local distribution company" (LDC) means any person, other than an interstate pipeline or an intrastate transmission pipeline, engaged in the sale and distribution of gas for end-user consumption. A LDC may also perform transportation services for its end-use customers, for another LDC and/or its end-use customers, as authorized under its effective Colorado jurisdictional tariffs.
  - (t) "Local government" means any Colorado county, municipality, city and county, home rule city or town, home rule city and county, or city or town operating under a territorial charter.
  - (u) "Local office" means any Colorado office operated by a utility at which persons may make requests to establish or to discontinue utility service. If the utility does not operate an office in Colorado, "local office" means any office operated by a utility at which persons may make requests to establish or to discontinue utility service in Colorado.
  - (v) "Main" means a distribution line that serves, or is designed to serve, as a common source of supply for more than one service lateral.

- (w) "Mcf" means 1,000 standard cubic feet.
- (x) "MMBtu" means 1,000,000 British Thermal Units, or one Dekatherm.
- (y) "Non-standard customer data" means all customer data that are not standard customer data.
- (z) "Past due" means the point at which a utility can affect a customer's account for regulated service due to non-payment of charges for regulated service.
- (aa) "Pipeline system" means the piping and associated facilities used in the transmission and/or distribution of gas.
- (bb) "Principal place of business" means the place, in or out of the State of Colorado, where the executive or managing principals who directly oversee the utility's operations in Colorado are located.
- (cc) "Property owner" means the legal owner of government record for a parcel of real property within the service territory of a utility. A utility may rely upon the records of a county clerk for the county within which a parcel of real property is located to determine ownership of government record.
- (dd) "Regulated charges" means charges billed by a utility to a customer if such charges are approved by the Commission, presented on a tariff sheet, and/or contained in a tariff of the utility.
- (ee) "Sales customer" means a person who receives sales service from a utility.
- (ff) "Sales service" means a bundled gas utility service in which the utility both purchases gas commodity for resale to the customer and delivers the gas to the customer.
- (gg) "Security" includes any stock, bond, note, or other evidence of indebtedness.
- (hh) "Service lateral" means that part of a distribution system from the utility's main to the entrance to a customer's physical location.
- (ii) "Standard conditions" means gas at a temperature of 60 degrees Fahrenheit and subject to an absolute pressure equal to 14.73 pounds per square inch absolute.
- (jj) "Standard customer data" means customer data maintained by a utility in its systems in the ordinary course of business.
- (kk) "Standby capacity" means the maximum daily volumetric amount of capacity reserved in the utility's system for use by a transportation customer, if the customer purchased optional standby service.
- (ll) "Standby supply" means the daily volumetric amount of gas reserved by a utility for the use by a transportation customer should that customer's supply fail, if the customer purchased optional standby service.

- (mm) "Third party" means a person who is not the customer, an agent of the customer who has been designated by the customer with the utility and is acting on the customer's behalf, a regulated utility serving the customer, or a contracted agent of the utility.
- (nn) "Transportation" means the exchange, forward-haul, backhaul, flow reversal, or displacement of gas between a utility and a transportation customer through a pipeline system.
- (oo) "Transportation customer" means a person who, by signing a gas transportation agreement, elects to subscribe to gas transportation service offered by a utility.
- (pp) "Unique identifier" means customer's name, mailing address, telephone number, or email address that is displayed on a bill.
- (qq) "Unregulated charges" means charges that are billed by a utility to a customer and that are not regulated or approved by the Commission, are not contained in a tariff, and are for service or merchandise not required as a condition of receiving regulated utility service.
- (rr) "Upstream pipeline" means either a natural gas pipeline or a LDC that provides gas to a LDC.
- (ss) "Utility" means a public utility as defined in § 40-1-103, C.R.S., providing sales service or transportation service (or both) in Colorado. This term includes both an ITP and a LDC.
- (tt) "Utility service" or "service" means a service offering of a utility, which service offering is regulated by the Commission.
- (uu) "Whole building data" means the sum of the monthly gas use for either all service connections at a building on a parcel of real property or all buildings on a parcel of real property.

**4002. Applications.**

- (a) Any person may seek Commission action regarding any of the following matters through the filing of an appropriate application to request a(n):
  - (I) issuance or extension of a certificate of public convenience and necessity for a franchise, as provided in rule 4100;
  - (II) issuance or extension of a certificate of public convenience and necessity for service territory, as provided in rule 4101;
  - (III) issuance of a certificate of public convenience and necessity for construction of facilities, as provided in rule 4102;
  - (IV) amendment of a certificate of public convenience and necessity to change, extend, curtail, abandon, or discontinue any service or facility, as provided in rule 4103;
  - (V) transfer a certificate of public convenience and necessity, to obtain a controlling interest in any utility, to transfer assets within the jurisdiction of the Commission or stock, or to merge a utility with another entity, as provided in rule 4104;

- (VI) approval of the issuance or assumption of any security, or to create a lien pursuant to § 40-1-104, as provided in rule 4105;
  - (VII) flexible regulatory treatment to provide service without reference to tariffs, as provided in rule 4106;
  - (VIII) amendment of a tariff on less than statutory notice, as provided in rule 4109;
  - (IX) approval of a meter sampling program, as provided in rule 4304;
  - (X) approval of a refund plan, as provided in rule 4410;
  - (XI) approval of a Low-Income Energy Assistance Plan, as provided in rule 4411;
  - (XII) approval of a cost assignment and allocation manual, as provided in rule 4503;
  - (XIII) appeal of a local government land use decision, as provided in rule 4703; or
  - (XIV) any other matter not specifically described in this rule, unless such matter is required to be submitted as a petition under rule 1304, as a motion, or as some other specific type of submittal.
- (b) In addition to the requirements of specific rules, all applications shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
- (I) the name and address of the applying utility;
  - (II) the name(s) under which the applying utility is, or will be, providing service in Colorado;
  - (III) the name, address, telephone number, and e-mail address of the applying utility's representative to whom all inquiries concerning the application should be made;
  - (IV) a statement that the applying utility agrees to answer all questions propounded by the Commission or Commission staff concerning the application;
  - (V) a statement that the applying utility shall permit the Commission or Commission staff to inspect the applying utility's books and records as part of the investigation into the application;
  - (VI) a statement that the applying utility understands that, if any portion of the application is found to be false or to contain material misrepresentations, any authorities granted pursuant to the application may be revoked upon Commission order;
  - (VII) in lieu of the separate statements required by subparagraphs (b)(IV) through (VI) of this rule, a utility may include a statement that it has read, and agrees to abide by, the provisions of subparagraphs (b)(IV) through (VI) of this rule;

- (VIII) a statement describing the applying utility's existing operations and general service area in Colorado.
  - (IX) for applications listed in subparagraphs (a)(I), (II), (III), (V), and (VI) of this rule, the applying utility's or parent company's and consolidated subsidiaries' most recent audited balance sheet, income statement, statement of retained earnings, and statement of cash flows so long as they provide Colorado specific financial information;
  - (X) a statement indicating the town or city, and any alternative town or city, in which the applying utility prefers any hearing be held; and
  - (XI) acknowledgment that, by signing the application, the applying utility understands that:
    - (A) the filing of the application does not by itself constitute approval of the application;
    - (B) if the application is granted, the applying utility shall not commence the requested action until the applying utility complies with applicable Commission rules and with any conditions established by Commission order granting the application; and
    - (C) if a hearing is held, the applying utility shall present evidence at the hearing to establish its qualifications to undertake, and its right to undertake, the requested action.
    - (D) in lieu of the statements contained in subparagraphs (b)(XI)(A) through (C) of this rule, an applying utility may include a statement that it has read, and agrees to abide by, the provisions of subparagraphs (b)(XI)(A) through (C) of this rule.
  - (XII) An attestation which is made under penalty of perjury; which is signed by an officer, a partner, an owner, an employee of, an agent for, or an attorney for the applying utility, as appropriate, who is authorized to act on behalf of the applying utility; and which states that the contents of the application are true, accurate, and correct. The application shall contain the title and the complete address of the affiant.
- (c) In addition to the requirements of specific rules, all applications shall include the information listed in subparagraphs (a)(I) through (V) of rule 1310. Applying utilities may either include the information in the application itself, or incorporate the information by reference to the most recent miscellaneous proceeding created under rule 1310.

- (d) Customer notice. Except as required or permitted by § 40-3-104, C.R.S., if the applicant is required by statute, Commission rule, or order to provide notice to its customers of the application, the applicant shall, within seven days after filing an application with the Commission, cause to have published notice of the filing of the application in each newspaper of general circulation in the municipalities impacted by the application. The applicant shall provide proof of such customer notice within 14 days of the publication in the newspaper. Failure to provide such notice or failure to provide the Commission with proof of notice may cause the Commission to deem the application incomplete. The applicant may also be required by statute, Commission rule, or order to provide additional notice to its customers of the application by first-class mailing or by hand-delivery. Both the newspaper notice and any additional customer notice(s) shall include the following:
- (I) the title “Notice of Application by [Name of the Utility] to [Purpose of Application]”;
  - (II) state that [Name of Utility] has applied to the Colorado Public Utilities Commission for approval to [Purpose of Application]. If the utility commonly uses another name when conducting business with its customers, the “also known as” name should also be identified in the notice to customers;
  - (III) provide a brief description of the proposal and the scope of the proposal, including an explanation of the possible impact upon persons receiving the notice;
  - (IV) identify which customer class(es) will be affected and the monthly customer rate impact by customer class, if customers’ rates are affected by the application;
  - (V) identify the proposed effective date of the application;
  - (VI) identify that the application was filed on less than statutory notice or if the applicant requests an expedited Commission decision, as applicable;
  - (VII) state that the filing is available for inspection in each local office of the applicant and at the Colorado Public Utilities Commission;
  - (VIII) identify the proceeding number, if known at the time the customer notice is provided;
  - (IX) state that any person may file written comment(s) or objection(s) concerning the application with the Commission. As part of this statement, the notice shall identify both the address and e-mail address of the Commission and shall state that the Commission will consider all written comments and objections submitted prior to the evidentiary hearing on the application;
  - (X) state that if a person desires to participate as a party in any proceeding before the Commission regarding the filing, such person shall file an intervention in accordance with the rule 1401 of the Commission’s Rules of Practice and Procedure or any applicable Commission order;



- (XI) state that the Commission may hold a public hearing in addition to an evidentiary hearing on the application and that if such a hearing is held members of the public may attend and make statements even if they did not file comments, objections or an intervention. State that if the application is uncontested or unopposed, the Commission may determine the matter without a hearing and without further notice; and
- (XII) state that any person desiring information regarding if and when hearings may be held shall submit a written request to the Commission or, alternatively, shall contact the External Affairs section of the Commission at its local or toll-free phone number. Such statement shall also identify both the local and toll-free phone numbers of the Commission's External Affairs section.

**4003. [Reserved].**

**4004. Disputes and Informal Complaints.**

- (a) For purposes of this rule, "dispute" means a concern, difficulty, or problem which needs resolution and which a customer or a person applying for service brings directly to the attention of the utility without the involvement of the Commission or Commission staff.
- (b) A dispute may be initiated orally or in writing. Using the procedures found in rule 1301, a utility shall conduct a full and prompt investigation of all disputes concerning utility service.
- (c) In accordance with the procedures in rule 1301, a utility shall conduct a full and prompt investigation of all informal complaints concerning utility service.
- (d) A utility shall comply with all rules regarding the timelines for responding to informal complaints.
- (e) If a current customer, or an applicant for service that is not a current customer, is dissatisfied with the utility's proposed adjustment or disposition of a dispute, the utility shall inform the person, customer or applicant for service of the right to make an informal complaint to the External Affairs section of the Commission and shall provide to the person, customer or applicant for service the address and toll free number of the Commission's External Affairs section.
- (f) A utility shall keep a record of each informal complaint and of each dispute. The record shall show the name and address of the initiating customer or person applying for service, the date and character of the issue, and the adjustment or disposition made. This record shall be open at all times to inspection by the person who initiated the informal complaint or dispute, by the Commission, and by Commission staff.

**4005. Records.**

- (a) Except as a specific rule may require, every utility shall maintain, for a period of not less than three years, and shall make available for inspection at its principal place of business during regular business hours, the following:
  - (I) records concerning disputes, which records are created pursuant to rule 4004;

- (II) complete records of tests to determine the heating value of gas, which records are created pursuant to rule 4202;
  - (III) records concerning interruptions and curtailments of service, which records are created pursuant to rule 4203;
  - (IV) transportation request logs, which records are created pursuant to paragraph 4205(e);
  - (V) notices of rejected transportation requests, which records are created pursuant to paragraph 4206(c);(VI) transportation agreements created pursuant to rule 4206;
  - (VII) all distribution pressure records, and all records or charts made with respect to rule 4208, appropriately annotated;
  - (VIII) meter calibration records created pursuant to under rule 4303;
  - (IX) records concerning meters, which records are created pursuant to rules 4305 and 4306;
  - (X) customer billing records, which records are created pursuant to paragraph 4401(a);
  - (XI) customer deposit records, which records are created pursuant to rule 4403;
  - (XII) records and supporting documentation concerning its cost assignment and allocation manual and fully-distributed cost study pursuant to paragraphs 4503(g) and 4504(e), for so long as the manual and study are in effect or are the subject of a complaint or a proceeding before the Commission;
  - (XIII) the total gas transported under each transportation service in Mcf or MMBtu and the associated total revenue;
  - (XIV) records concerning demand side management, pursuant to rules 4750 through 4760; and
  - (XV) as applicable, the records and documents required to be created pursuant to rules 4910 through 4920.
- (b) A utility shall maintain at each of its local offices and at its principal place of business all tariffs filed with the Commission and applying to Colorado rate areas. If the utility maintains a website, it shall also maintain its current and complete tariffs on its website.
- (c) A utility shall maintain its books of account and records in accordance with the provisions of 18 C.F.R. Part 201, the Uniform System of Accounts. A utility shall maintain its books of accounts and records separately and apart from those of its affiliates.
- (d) A utility shall preserve its records in accordance with the provisions of 18 C.F.R. Part 225, the Preservation of Records of Public Utilities and Licensees.

**4006. Reports.**

- (a) On or before April 30th of each year, a utility shall file with the Commission an annual report for the preceding calendar year. The utility shall submit the annual report on forms prescribed by the Commission; shall properly complete the forms; shall ensure the forms are verified and signed by a person authorized to act on behalf of the utility; and shall file in accordance with subparagraph 1204(a)(III) of the Commission's Rules of Practice and Procedure. If the Commission grants the utility an extension of time to file the annual report, the utility nevertheless shall file with the Commission, on or before April 30, the utility's total gross operating revenue from intrastate utility business transacted in Colorado for the preceding calendar year.
- (b) If a certified public accountant prepares an annual report for a utility, the utility shall file, within 30 days after the report is final, either two paper copies of the report with the Commission or an electronic copy through the Commission's E-Filing System.
- (c) On an annual basis, a utility shall file a report stating the average time taken for service personnel to respond to gas odor calls from customers for the following:
  - (I) the entire area served by the utility within Colorado; and
  - (II) each division of the utility assigned to serve a region or portion of the utility's entire service area.

**4007. [Reserved]**

**4008. Incorporation by Reference.**

- (a) The Commission incorporates by reference 18 C.F.R. Part 201 (as published on April 1, 2012) regarding the Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act. No later amendments to or editions of 18 C.F.R. Part 201 are incorporated into these rules.
- (b) The Commission incorporates by reference 18 C.F.R. Part 225 (as published on April 1, 2012) regarding the Preservation of Records of Natural Gas Companies. No later amendments to or editions of 18 C.F.R. Part 225 are incorporated into these rules.
- (c) Any material incorporated by reference in this Part 4 may be examined at the offices of the Commission, 1560 Broadway, Suite 250, Denver, Colorado 80202, during normal business hours, Monday through Friday, except when such days are state holidays. . Incorporated standards shall be available electronically and provided in certified copies, at cost, upon request. Restrictions on the provision of physical copies due to copyright protections may apply. The Director or the Director's designee will provide information regarding how the incorporated standards may be examined at any state public depository library. The standards and regulations are also available from the agency, organization or association originally issuing the code, standard, guideline or rule as follows: Code of Federal Regulations: [www.govinfo.gov/help/cfr](http://www.govinfo.gov/help/cfr).

## **CIVIL PENALTIES**

### **4009. Definitions.**

The following definitions apply to rules 4009, 4010, and 4976, unless a specific statute or rule provides otherwise. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- (a) “Civil penalty” means any monetary penalty levied against a public utility because of intentional violations of statutes in Articles 1 to 7 and 15 of Title 40, C.R.S., Commission rules, or Commission orders.
- (b) “Civil penalty assessment” means the act by the Commission of imposing a civil penalty against a public utility after the public utility has admitted liability or has been adjudicated by the Commission to be liable for intentional violations of statutes in Articles 1 to 7 and 15 of Title 40, C.R.S., Commission rules, or Commission orders.
- (c) “Civil penalty assessment notice” means the written document by which a public utility is given notice of an alleged intentional violation of statutes in Articles 1 to 7 and 15 of Title 40, C.R.S., Commission rules, or Commission orders and of a proposed civil penalty.
- (d) “Intentional violation.” A person acts “intentionally” or “with intent” when his conscious objective is to cause the specific result proscribed by the statute, rule, or order defining the violation.

### **4010. Regulated Gas Utility Violations, Civil Enforcement, and Enhancement of Civil Penalties.**

- (a) The Commission may impose a civil penalty in accordance with the requirements and procedures contained in § 40-7-113.5, C.R.S., § 40-7-116.5, C.R.S., and paragraph 1302(b), 4 Code of Colorado Regulations 723-1, for intentional violations of statutes in Articles 1 to 7 and 15 of Title 40, C.R.S., Commission rules, or Commission orders as specified in §§ 40-7-113.5 and 40-7-116.5, C.R.S., and in these rules.
- (b) The Director of the Commission or his or her designee shall have the authority to issue civil penalty assessments for the violations enumerated in § 40-7-113.5, C.R.S., subject to hearing before the Commission. When a public utility is cited for an alleged intentional violation, the public utility shall be given notice of the alleged violation in the form of a civil penalty assessment notice.
- (c) The public utility cited for an alleged intentional violation may either admit liability for the violation pursuant to § 40-7-116.5(1)(c) or the public utility may contest the alleged violation pursuant to § 40-7-116.5(1)(d), C.R.S. At any hearing contesting an alleged violation, trial staff shall have the burden of demonstrating a violation by a preponderance of the evidence.
- (d) In any written decision entered by the Commission pursuant to § 40-6-109, C.R.S., adjudicating a public utility liable for an intentional violation of a statute in Articles 1 to 7 and 15 of Title 40, C.R.S., a Commission rule, or a Commission order, the Commission may impose a civil penalty of not more than two thousand dollars, pursuant to § 40-7-113.5(1), C.R.S. In imposing any civil penalty pursuant to § 40-7-113.5(1), C.R.S., the Commission shall consider the factors set forth in Rule 1302(b).

- (e) The Commission may assess doubled or tripled civil penalties against any public utility, as provided by § 40-7-113.5(3), C.R.S., § 40-7-113.5(4), C.R.S., and this rule.
- (f) The Commission may assess any public utility a civil penalty containing doubled penalties only if:
  - (I) the public utility has admitted liability by paying the civil penalty assessment for, or has been adjudicated by the Commission in an administratively final written decision to be liable for, engaging in prior conduct that constituted an intentional violation of a statute in Articles 1 to 7 and 15 of Title 40, C.R.S., a Commission rule, or a Commission order;
  - (II) the conduct for which doubled civil penalties are sought violates the same statute, rule, or order as conduct for which the public utility has admitted liability by paying the civil penalty assessment, or conduct for which the public utility has been adjudicated by the Commission in an administratively final written decision to be liable; and
  - (III) the conduct for which doubled civil penalties are sought occurred within one year after conduct for which the public utility has admitted liability by paying the civil penalty assessment, or conduct for which the public utility has been adjudicated by the Commission in an administratively final written decision to be liable
- (g) The Commission may assess any public utility a civil penalty containing tripled penalties only if:
  - (I) the public utility has admitted liability by paying the civil penalty assessment for, or has been adjudicated by the Commission in an administratively final written decision to be liable for, engaging in prior conduct that constituted two or more prior intentional violations of a statute in Articles 1 to 7 and 15 of Title 40, C.R.S., a Commission rule, or a Commission order;
  - (II) the conduct for which tripled civil penalties are sought violates the same statute, rule, or order as conduct for which the public utility has either admitted liability by paying the civil penalty assessment or been adjudicated by the Commission in an administratively final written decision to be liable, in at least two prior instances; and
  - (III) the conduct for which tripled civil penalties are sought occurred within one year after the two most recent prior instances of conduct for which the public utility has either admitted liability by paying the civil penalty assessment, or been adjudicated by the Commission in an administratively final written decision to be liable.
- (h) When more than two instances of prior conduct exist, the Commission shall only consider those instances occurring within one year prior to the date of such alleged conduct for which tripled civil penalties are sought.
- (i) Nothing in this rule shall preclude the assessment of tripled penalties when doubled and tripled penalties are sought in the same civil penalty assessment notice.
- (j) The Commission shall not issue a decision on doubled or tripled penalties until after the effective date of the administratively final Commission decision upon which the single civil penalty was based.

- (k) The civil penalty assessment notice shall contain the maximum penalty amount provided by rule for each individual violation noted, with a separate provision for a reduced penalty of 50 percent of the penalty amount sought if paid within ten days of the public utility's receipt of the civil penalty assessment notice.
- (l) The civil penalty assessment notice shall contain the maximum amount of the penalty surcharge pursuant to § 24-34-108(2), C.R.S., if any.
- (m) A penalty surcharge referred to in paragraph (l) of this rule shall be equal to the percentage set by the Department of Regulatory Agencies on an annual basis. The surcharge shall not be included in the calculation of the statutory limits set in § 40-7-113.5(5), C.R.S.
- (n) Nothing in these rules shall affect the Commission's ability to pursue other remedies in lieu of issuing civil penalties.

**4011. – 4024. [Reserved].**

**CUSTOMER DATA ACCESS AND PRIVACY**

**4025. Scope and Applicability.**

- (a) The basis and purpose of these rules is to describe the protection of and limited access to customer data for gas utilities over which the Commission has jurisdiction. These rules are applicable to all utilities except for certain provisions as defined in the rule.
- (b) For the purpose of the Customer Data Access and Privacy Rules, gas utilities are classed into three tiers: a Tier I utility serves more than 150,000 gas customers; a Tier II utility serves between 50,000 and 150,000 gas customers. A Tier III utility serves fewer than 50,000 gas customers.
- (c) No Tier III utility is required to:
  - (I) include in its tariffs a description of standard and non-standard customer data that the utility is able to provide to the customer or to any third party recipient (see paragraph 4027(c));
  - (II) provide customer notice each year regarding customer data (see rule 4028);
  - (III) make customer consent forms for the disclosure of customer data available to customers or third parties (see rule 4029);
  - (IV) disclose aggregated data (see rule 4033); or
  - (V) provide a community energy report (see rule 4035).

However, a Tier III utility may include a description of standard and non-standard customer data that the utility is able to provide to the customer or to any third-party recipient in its tariffs (in accordance with paragraph 4027(c)). Commencing upon the effective date of such description, the Tier III utility shall be deemed to be a Tier II utility for purposes of these Customer Data Access and Privacy Rules for so long as such tariff provisions remain in effect.

**4026. Customer Data.**

- (a) A utility shall maintain standard customer data sufficient to allow a customer to understand his or her energy usage at a level of detail commensurate with the metering technology used to serve the customer.

**4027. Privacy, Access, and Disclosure.**

- (a) A utility shall protect customer data in the utility's possession or control to maintain the privacy of customers, while providing reasonable access to that data. A utility is only authorized to use customer data to provide regulated utility service in the ordinary course of business.
- (b) A utility shall not disclose customer data unless such disclosure conforms to these rules, except as required by law or to comply with Commission rule. Illustratively, this includes responses to requests of the Commission, warrants, subpoenas, court orders, or as authorized by § 16-15.5-102, C.R.S.
- (c) A utility shall include in its tariffs a description of customer data that the utility is able to provide to the customer or to any third party recipient to whom the customer has authorized disclosure of the customer's data within the utility's technological and data capabilities. At a minimum, the utility's tariff must provide the following:
  - (I) a description of standard customer data and non-standard customer data and the frequency of customer data updates that will be available (annual, monthly, daily, etc.);
  - (II) the method and frequency of customer data transmittal and access available (electronic, paper, etc.) as well as the security protections or requirements for such transmittal;
  - (III) a timeframe for processing requests;
  - (IV) any rate associated with processing a request for non-standard customer data; and
  - (V) any charges associated with obtaining non-standard customer data.
- (d) As part of basic utility service, a utility shall provide access to the customer's standard customer data in electronic machine-readable form, without additional charge, to the customer or to any third party recipient to whom the customer has authorized disclosure of the customer's customer data. Such access shall conform to nationally recognized open standards and best practices. The utility shall provide access in a manner that ensures adequate protections for the utility's system security and the continued privacy of the customer data during transmission.
- (e) Nothing in these rules shall limit a customer's right to provide his or her customer data to anyone.

- (f) A utility and each of its directors, officers and employees that discloses customer data pursuant to a customer's authorization in accordance with these data privacy rules shall not be liable or responsible for any claims for loss or damages resulting from the utility's disclosure of customer data.

**4028. Customer Notice.**

- (a) A utility shall provide each year to its customers a written notice complying with this rule. The utility shall conspicuously post on its website notice of its privacy and security policies governing access to and disclosure of customer data and aggregated data to third-parties. This notice shall:
- (I) explain what is available to customers, as standard and/or non-standard customer data (e.g., daily versus hourly data);
  - (II) describe the frequency that the utility can provide customer data based on a request for standard data (e.g., on a weekly or monthly basis);
  - (III) advise customers that their customer data may provide insight into their activities within the premises receiving service;
  - (IV) inform customers that the privacy and security of their customer data will be protected by the utility while in its possession;
  - (V) explain that customers can access their standard customer data, as identified by the utility's tariff, without additional charge;
  - (VI) advise customers that their customer data will not be disclosed to third parties, except:
    - (A) as necessary to provide regulated utility services to the customers;
    - (B) as otherwise permitted or required by law or Commission rule; or
    - (C) pursuant to the authorization given by the customer in accordance with these rules.
  - (VII) describe the utility's policies regarding how a customer can authorize access and disclosure of their customer data to third-parties. With regard to such third party data disclosure, the notice shall:
    - (A) inform customers that declining a request for disclosure of customer data to a third party will not affect the provision of utility service that the customer receives from the utility; and
    - (B) explain that any customer consent for access to, disclosure of, or use of a customer's customer data by a third party may be terminated or limited by the customer of record at any time and inform the customers of the process for doing so.



- (VIII) explain that aggregated data does not contain customer identifying information and inform customers that customer data may be used to create aggregated data that will not contain customer identifying information;
- (IX) explain that the utility may provide aggregated data to third-parties, subject to its obligation under paragraph 4033(a);
- (X) be viewable on-line and printed in ten point or larger font;
- (XI) be sent either separately or included as an insert in a regular monthly bill, or, for those customers who have consented to receive e-bills, such notice may be sent electronically separately from an e-bill, conspicuously marked and stating clearly that important information on the utility's privacy practices is contained therein;
- (XII) be available in English and Spanish. The customer notice may also be translated to a language other than English or Spanish by a third party or the utility. Forms translated to other languages in accordance with this rule must be accepted by utilities, and may be relied upon, after the English version of the form, the translated version of the form, and an affidavit attesting to the accurate and complete translation from the English version of the form, have been provided to the Commission and the utility possessing the data. Such affidavit must be executed by an interpreter on the active roster of interpreters maintained by the Office of Language Access of the Colorado Judicial Branch. If the utility incurs a cost for translation made at the request of a third party, it may charge the requestor for such cost and may include a reasonable administrative fee in addition to the translation cost; and
- (XIII) provide a customer service phone number and web address where customers can direct additional questions or obtain additional information regarding their customer data, the disclosure of customer data or aggregated data, or the utility's privacy policies and procedures with respect to customer data or aggregated data.

**4029. Customer Consent Form for the Disclosure of their Customer Data to Third Party Recipients by a Utility.**

- (a) A utility shall make available to any third party a consent form for the disclosure of customer data that is maintained by the Commission and available from the Commission's website. The form shall be available electronically from the utility. The consent form shall be provided in a non-electronic format by a utility upon request from a customer or third party.
- (b) In addition to the Commission supplied form, a utility may create and make available a consent form that:
  - (I) includes the same information contained in the annual notice provided under subparagraphs 4028(a)(V), (VI), (VII), and (XIII);
  - (II) provides spaces for the following required information regarding the third party recipient of the customer data:

- (A) the name, including trade name if applicable, physical address, mailing address, e-mail address, and telephone number;
  - (B) the uses of the data for which the customer is allowing disclosure;
  - (C) the time period (e.g., months, years) for which data are being requested; and
  - (D) the description of the data that are being requested;
- (III) states that the consent is valid until terminated;
- (IV) states that the customer must notify the utility service provider in writing (electronically or non-electronically) to terminate the consent including appropriate utility contact information;
- (V) states any additional terms except an inducement for the customer's disclosure;
- (VI) be viewable on-line and printed in ten point or larger font; and
- (VII) provides notice to the customer that the utility shall not be responsible for monitoring or taking any steps to ensure that the third party to whom the data is disclosed is maintaining the confidentiality of the data or using the data as intended by the customer.
- (c) A utility may make available an electronic customer consent process for disclosure of customer data to a third party (e.g., a utility controlled web portal) that authenticates the customer identity. The contents of the electronic consent process must generally follow the format of the model consent to disclose customer data form, be clear, and include the elements to be provided pursuant to paragraph (a) of this rule. No utility is required to provide an electronic consent process in a language other than English.
- (d) A utility may make available an in-person consent process for disclosure of customer data.
- (e) A consent form may be submitted to the utility through electronic or non-electronic methods.
- (f) The scope of consent given shall be defined by the terms of the consent form, except that changes of contact names for an organization, trade name, or utility over time do not invalidate consent as to the respective organization, trade name, or utility. Because the contact named for an organization, trade name, or utility is a representative of the respective organization, trade name, or utility, consent terminates as to such contact when the relationship with the organization, trade name, or utility terminates. Modifications to the consent form over time do not invalidate previous consent. Consent need not be provided on a new form so long as the data provided remains within the scope of consent.
- (g) Customer consent forms shall be available in English and Spanish. Customer consent forms may be translated to into languages other than English or Spanish by a third party or the utility. Forms translated to other languages in accordance with this rule must be accepted by utilities, and may be relied upon, after the English version of the form, the translated version of the form, and an affidavit attesting to the accurate and complete translation from the English version of the form, have been provided to the Commission and the utility possessing the data. Such affidavit must

be signed by an interpreter on the active roster of interpreters maintained by the Office of Language Access of the Colorado Judicial Branch. If a utility incurs a cost for a translation at the request of a third party, it may charge the requestor for such cost and may include a reasonable administrative fee in addition to the translation cost.

- (h) Any customer consent forms available from the Commission's website shall be presumed to comply with these rules.

**4030. Access to Customer Data for the Provision of Regulated Utility Service.**

- (a) A utility may disclose customer data to a contracted agent provided that the contract requires the agent to:
  - (I) implement and maintain data security procedures and practices to protect the customer data from unauthorized access, destruction, use, modification, or disclosure that are equal to or greater than the data privacy and security policies and procedures used by the utility internally to protect customer data;
  - (II) use customer data solely for the purpose of the contract and prohibits the use of customer data for a secondary commercial purpose not related to the purpose of the contract without first obtaining the customer's consent as provided for in these rules;
  - (III) return to the utility or destroy any customer data that is no longer necessary for the purpose for which it was transferred; and
  - (IV) execute a non-disclosure agreement with the utility.
- (b) The utility shall maintain records of the disclosure of customer data to contracted agents for a minimum of three years. Such records shall include all contracts with the contracted agent and executed non-disclosure agreements.

**4031. Local Government Access to Customer Data from a Utility for Audit.**

- (a) A utility may disclose customer data to a local government either with an audit required to be provided pursuant to a final Commission decision (e.g., a decision approving a franchise agreement) or as reasonably necessary for an audit conducted by a governmental entity of franchise fees paid to them by the utility, provided that:
  - (I) disclosure is not otherwise prohibited by a final Commission decision (e.g., Commission-approved franchise between the utility and the local government);
  - (II) disclosure is made to a designated auditor or auditor's office, who is either an employee or agent of the local government;
  - (III) the auditor collects and uses the customer data solely for the purpose of reviewing or conducting the audit and is prohibited from disclosing or using the customer data for a purpose not related to the audit;

- (IV) the local government implements and maintains data security procedures and practices to protect the customer data from unauthorized access, destruction, use, or modification;
  - (V) the local government destroys or returns to the utility of any customer data no longer necessary for the purpose for which it was transferred unless state law or the municipality's state-mandated retention schedule requires otherwise;
  - (VI) the local government agrees not to permit access to the data by anyone that has not agreed to abide by the terms pursuant to which the data was provided by the utility. This includes, but is not limited to, all interns, subcontractors, staff, other workforce members, and consultants;
  - (VII) the local government agrees that any recipient of the data pursuant to this rule does not obtain any right, title or interest in any of the data provided by the utility;
  - (VIII) governing law or a non-disclosure agreement executed with the utility requires that the local government, at a minimum, comply with the requirements of this rule; and
  - (IX) the data requested is for utility customers served in the boundaries of the local government.
- (b) The utility shall maintain records of all disclosures of customer data to local government requestors for a minimum of three years.
- (c) Availability of customer data pursuant to this rule does not preclude a local government from requesting other data reports.

**4032. Third Party Access to Customer Data from a Utility.**

- (a) Except as provided in this rule, paragraph 4027(b), rule 4030, and rule 4031, a utility shall not disclose customer data to any third party unless the customer or a third party acting on behalf of a customer submits a paper or electronic signed consent to disclose customer data form that has been executed by the customer of record.
- (b) Incomplete or non-compliant consent to disclose customer data forms are not valid and shall be rejected by the utility.
- (c) The utility shall maintain records of all of the disclosures of customer data to third party requestors. Such records shall include a copy of the customer's signed consent to disclose customer data form, all identifying documentation produced by the third party requestor, the customer's agreed upon terms of use, the date(s) and frequency of disclosure, and a description of the customer data disclosed.
- (d) The utility shall maintain records of customer data disclosures for a minimum of three years and shall make the records of the disclosure of a customer's customer data available for review by the customer within five business days of receiving a paper or electronic request from the customer, or at such greater time as is mutually agreed between the utility and the customer.

**4033. Requests for Aggregated Data Reports from a Utility.**

- (a) A utility shall not disclose aggregated data unless the recipient is authorized to receive all customer data within the aggregated data, and the disclosure otherwise conforms to this rule and rules 4031, 4034, and 4035. In aggregating customer data to create an aggregated data report, a utility must ensure that the data do not include any personal information or a unique identifier.
- (b) At a minimum, a particular aggregation must contain at least fifteen customers; and, within any customer class no single customer's customer data or premise associated with a single customer's customer data may comprise 15 percent or more of the total customer data aggregated per customer class to generate the aggregated data report (the "15/15 Rule").
- (c) If an aggregated data report cannot be generated in compliance with paragraph 4033(b), the utility shall notify the requestor that the aggregated data, as requested, cannot be disclosed and identify the reason(s) the request was denied. The requestor shall be given an opportunity to revise its aggregated data request in order to address the identified reason(s). An aggregated data request may be revised by expanding the number of customers or premise accounts in the request, expanding the geographic area included in the request, combining different customer classes or rate categories, or other applicable means of aggregating.
- (d) A utility shall include in its tariffs a description of standard and non-standard aggregated data reports available from the utility to any requestor. At a minimum, the utility's tariff shall provide the following:
  - (I) a description of standard and non-standard aggregated data reports available from the utility including all available selection parameters (customer data or other data);
  - (II) the frequency of data collection (annual, monthly, daily, etc.);
  - (III) the method of transmittal available (electronic, paper, etc.) and the security protections or requirements for such transmittal;
  - (IV) the charge for providing a standard aggregated data report or the hourly charge for compiling a non-standard aggregated data report;
  - (V) the timeframe for processing requests; and
  - (VI) a request form for submitting a data request for aggregated data reports to the utility identifying any information necessary from the requestor in order for the utility to process the request.
- (e) If a utility is unable to fulfill a non-standard aggregated data report request because it does not have and/or does not elect to or cannot obtain all of the data the requestor wishes to include in the aggregated data report, then the utility may contract with a contracted agent to include the additional data and process it along with the customer data in the utility's possession, to generate a non-standard aggregated data report.

- (f) A utility and each of its directors, officers and employees that discloses aggregated data as provided in these data privacy rules shall not be liable or responsible for any claims for loss or damages resulting from the utility's disclosure of aggregated data.
- (g) A utility shall not provide aggregated customer data in response to multiple overlapping requests from or on behalf of the same requestor that have the potential to identify customer data.

**4034. Property Owner Request for Whole Building Energy Use Data from a Utility.**

- (a) If requested by a property owner or its authorized agent, a Tier I utility shall provide whole building energy use data to the property owner or its authorized agent so long as:
  - (I) the whole building energy use data contains at least four customers or tenants, which may include the property owner's own account; and no single customer's customer data, unless it is the property owner's, comprises more than 50 percent of the whole building energy use data used to generate the whole building energy use data report;
  - (II) the property owner or its authorized agent agrees to not disclose the whole building energy use data except for the purposes of building benchmarking, identifying energy efficiency projects, and energy management; and
  - (III) the property owner or its authorized agent signs a non-disclosure agreement with the utility requiring the property owner, at a minimum to:
    - (A) take appropriate administrative, technical, and physical safeguards to protect the whole building data from any unauthorized use or disclosure to protect the data from unauthorized access, destruction, use, modification, or disclosure;
    - (B) only use the whole building data only for the purposes of building benchmarking, identifying energy efficiency projects, energy management, and complying with laws or ordinances;
    - (C) agree not to attempt to determine an individual utility customer's energy use from the whole building data and not to use the information to contact the subject of the information;
    - (D) agree not to use the whole building energy use data for a secondary commercial purpose not related to the authorized purpose without first obtaining the customer's consent as provided for in these rules;
    - (E) destroy any whole building energy use data that is no longer necessary for the purpose for which it was transferred;
    - (F) agree not to permit access to the whole building data by anyone that has not agreed to abide by the terms pursuant to which the data was provided by the utility. This includes, but is not limited to, all interns, subcontractors, staff, other workforce members, and consultants; and

- (G) agree that any recipient of the whole building data pursuant to this rule does not obtain any right, title or interest in any of the data provided by the utility.
- (b) Upon request by a property owner or its authorized agent, a Tier II utility shall provide whole building energy use data upon the same conditions to the extent of, and based upon, information available in the ordinary course of business.
- (c) A utility shall provide a requested whole building energy use data report in electronic, machine readable format that conforms to nationally recognized open standards and best practices.
- (d) A utility may charge a property owner or its authorized agent for the development of a whole building energy use data report. Such rate shall be determined in a utility tariff as a non-standard aggregated data report. Alternatively, the utility need not charge the customer if the cost to charge a property owner or its authorized agent is greater than the cost to develop a whole building energy use data report.
- (e) Availability of whole building energy use data pursuant to this rule does not preclude a property owner from requesting other data reports.

**4035. Community Energy Reports.**

- (a) A Tier I utility shall generate a community energy report for each local government other than a Colorado county included in its service territory with 50,000 or more residents. A Tier I utility shall generate a community energy report for each Colorado county included in its service territory with 100,000 or more residents. Any local government with fewer than 50,000 residents and Colorado county with fewer than 100,000 residents or a minority of whom are served by a Tier I utility shall be treated as if it had 50,000 or more residents served by the Tier I upon request from the local government or county. Such requests shall be made by January 31 of the calendar year following the reporting year and shall continue in effect until such time as the request is withdrawn or cancelled by the local government. All population thresholds shall be based on the most recent population estimate from the Colorado State Demography Office and where the utility serves the majority of the population.
- (b) On or before June 1 of every year, a Tier I utility shall make publicly available for download all community energy reports generated for the prior year. Reports shall be available in an electronic machine-readable form that conforms to nationally recognized open standards and best practices.
- (c) The community energy report shall include the following information and aggregated data for the utility and its customers and specific to the local government for the prior calendar year:
  - (I) the annual dekatherms consumed by customers, provided by residential, commercial, and industrial classes;
  - (II) the average number of customers in the residential, commercial, and industrial class; and
  - (III) the total annual energy saved (in dekatherms) from energy efficiency measures installed.

- (d) A local government may submit, or have another local government submit on its behalf, a GIS data to define its jurisdictional boundaries prior to the issuance of the community energy report.
- (e) Upon request by a local government, a Tier II utility shall generate a community energy report, in accordance with this rule, consistent with the utility's meter, network, or data capabilities. Such requests shall be made by January 31 of the calendar year following the reporting year and shall continue in effect until such time as the request is withdrawn or cancelled by the local government. On or before June 1 of every year, the utility shall make publicly available for download all community energy reports generated for the prior year. Reports shall be available in an electronic machine-readable form that conforms to nationally recognized open standards and best practices.
- (f) Availability of the community energy report pursuant to this rule does not preclude a local government from requesting other data reports.

**4036.– 4099. [Reserved].**

## **OPERATING AUTHORITY**

### **4100. Certificate of Public Convenience and Necessity for a Franchise.**

- (a) A utility seeking authority to provide service pursuant to a franchise shall file an application pursuant to this rule. When a utility enters into a franchise agreement with a municipality for the first time, it shall obtain authority from the Commission pursuant to § 40-5-102, C.R.S. prior to providing service under that initial franchise agreement. A utility maintains the right and obligation to serve a municipality within its service territory after the expiration of any franchise agreement.
- (b) An application for certificate of public convenience and necessity to exercise franchise rights shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) the information required in paragraphs 4002(b) and 4002(c);
  - (II) a statement of the facts (not conclusory statements) relied upon by the applying utility to show that the public convenience and necessity require the granting of the application;
  - (III) a statement describing the franchise rights proposed to be exercised. The statement shall include a description of the type of utility service to be rendered and a description of the city or town sought to be served;
  - (IV) a certified copy of the franchise ordinance; proof of publication, adoption, and acceptance by the applying utility; a statement as to the number of customers served or to be served and the population of the city or town; and any other pertinent information;
  - (V) a statement describing in detail the extent to which the applying utility is an affiliate of any other utility which holds authority duplicating in any respect the authority sought;



- (VI) the feasibility study for areas previously not served by the applying utility, which study shall at least include estimated investment, income, and expense. An applying utility may request that its most recent audited balance sheet, income statement, statement of retained earnings, and statement of cash flows be submitted in lieu of a feasibility study; and
- (VII) a statement of the names of public utilities and other entities of like character providing similar service in or near the area sought to be served.

**4101. Certificate of Public Convenience and Necessity for Service Territory.**

- (a) A utility seeking authority to provide service in a new service territory shall file an application pursuant to this rule. A utility cannot provide service to a new geographic area without authority from the Commission, unless the utility extends its facilities and service:
  - (I) within a city and county or city or town within which the utility has lawfully commenced operations;
  - (II) into territory contiguous to the utility's facility, line, plant, or system that is not served by a public utility providing the same commodity or service; or
  - (III) within or to territory already served by the utility and the extension is necessary in the ordinary course of business.
- (b) An application for certificate of public convenience and necessity to provide service in a new territory shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) the information required in paragraphs 4002(b) and 4002(c);
  - (II) a statement of the facts (not conclusory statements) relied upon by the applying utility to show that the public convenience and necessity require the granting of the application;
  - (III) a description of the type of utility service to be rendered and a description of the area sought to be served;
  - (IV) a map showing the specific geographic area that the applying utility proposes to serve. If the applying utility intends to phase in service in the territory over time, specific areas and proposed in-service dates shall be included. The map shall describe the geographic areas in section, township, and range convention;
  - (V) a statement describing in detail the extent to which the applying utility is an affiliate of any other utility which holds authority duplicating in any respect the territory sought;
  - (VI) a statement of the names of public utilities and other entities of like character providing similar service in or near the area involved in the application;

- (VII) a feasibility study for the proposed area to be served, which shall at least include estimated investment, income, and expense. An applying utility may request that its most recent audited balance sheet, income statement, statement of retained earnings, and statement of cash flows be submitted in lieu of a feasibility study; and
- (VIII) a statement of the names of public utilities and other entities of like character providing similar service in or near the area sought to be served.

**4102. Certificate of Public Convenience and Necessity for Facilities.**

- (a) A utility seeking authority to construct and to operate a facility or an extension of a facility pursuant to § 40-5-101, C.R.S., shall file an application pursuant to this rule. The utility need not apply to the Commission for approval of construction and operation of a facility or an extension of a facility which is in the ordinary course of business. The utility shall apply to the Commission for approval of construction and operation of a facility or an extension of a facility which is not in the ordinary course of business.
- (b) An application for certificate of public convenience and necessity to construct and to operate facilities or an extension of a facility pursuant to § 40-5-101, C.R.S., shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) the information required in paragraphs 4002(b) and 4002(c);
  - (II) a statement of the facts (not conclusory statements) relied upon by the applying utility to show that the public convenience and necessity require the granting of the application or citation to any Commission decision that is relevant to the proposed facilities;
  - (III) a description of the proposed facilities to be constructed;
  - (IV) estimated cost of the proposed facilities to be constructed;
  - (V) anticipated construction start date, construction period, and in-service date;
  - (VI) a map showing the general area or actual locations where facilities will be constructed, population centers, major highways, and county and state boundaries; and
  - (VII) as applicable, information on alternatives studied, costs for those alternatives, and criteria used to rank or eliminate alternatives.

**4103. Certificate Amendments for Changes in Service, in Service Territory, or in Facilities.**

- (a) A utility seeking authority to do the following shall file an application pursuant to this rule: amend a certificate of public convenience and necessity in order to extend, to restrict, to curtail, or to abandon or to discontinue without equivalent replacement any service, service area, or facility. A utility shall not extend, restrict, curtail, or abandon or discontinue without equivalent replacement any service, service area, or facility not in the ordinary course of business without authority from the Commission.

- (b) An application to amend a certificate of public convenience and necessity in order to change, to extend, to restrict, to curtail, to abandon, or to discontinue any service, service area, or facility without equivalent replacement shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
- (I) all information required in paragraphs 4002(b) and 4002(c);
  - (II) if the application for amendment pertains to a certificate of public convenience and necessity for facilities, all of the information required in rule 4102;
  - (III) if the application for amendment pertains to a certificate of public convenience and necessity for franchise rights, all of the information required in rule 4100;
  - (IV) if the application for amendment pertains to a certificate of public convenience and necessity for service territory, all of the information required in rule 4101;
  - (V) if the application for amendment pertains to a service, the application shall include:
    - (A) the requested effective date for the extension, restriction, curtailment, or abandonment or discontinuance without equivalent replacement of the service; and
    - (B) a description of the extension, restriction, curtailment, or abandonment or discontinuance without equivalent replacement sought. This shall include maps, as applicable. This shall also include a description of the applying utility's existing operations and general service area.
- (c) Customer notice of application. In addition to complying with the notice requirements of the Commission's Rules Regulating Practice and Procedure, a utility applying to curtail, restrict, abandon or discontinue service without equivalent replacement shall prepare a written notice as provided in subparagraphs 4002(d)(I) through (XII) and shall mail or deliver the notice at least 30 days before the application's requested effective date to each of the applying utility's affected customers. The customer notice shall include a statement detailing the requested restriction, curtailment, or abandonment or discontinuance without equivalent replacement.
- (d) If no customers will be affected by the grant of the application, the notice must meet the requirements of subparagraphs 4002(d)(I) through (XII) and shall be mailed to the Board of County Commissioners of each affected county, and to the mayor of each affected city, town, or municipality.

**4104. Transfers, Controlling Interest, and Mergers.**

- (a) A utility seeking authority to do any of the following shall file an application pursuant to this rule: transfer a certificate of public convenience and necessity; transfer or obtain a controlling interest in a utility, whether the transfer of control is effected by the transfer of assets, by the transfer of stock, by merger or by other form of business combination; or transfer assets subject to the jurisdiction of the Commission outside the normal course of business. A utility cannot transfer a certificate of public convenience and necessity; transfer or obtain a controlling interest in any

utility; or transfer assets outside the normal course of business without authority from the Commission.

- (b) An application to transfer a certificate of public convenience and necessity, to transfer or obtain a controlling interest in a utility, or to transfer assets subject to the jurisdiction of the Commission shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
- (I) the information required in paragraphs 4002(b) and 4002(c), as pertinent to each party to the transaction;
  - (II) a statement showing accounting entries, under the Uniform System of Accounts, including any plant acquisition adjustment, gain, or loss proposed on the books by each party before and after the transaction which is the subject of the application;
  - (III) any agreement for merger, sales agreement, or contract of sale pertinent to the transaction which is the subject of the application;
  - (IV) all facts showing that the transaction which is the subject of the application is not contrary to the public interest;
  - (V) an evaluation of the benefits and detriments to the customers of each party and to all other persons who will be affected by the transaction which is the subject of the application; and.
  - (VI) a comparison of the kinds and costs of service rendered before and after the transaction which is the subject of the application.
- (c) An application to transfer a certificate of public convenience and necessity, an application to transfer assets subject to the jurisdiction of the Commission, or an application to transfer or obtain control of the utility may be made by joint or separate application of the transferor and the transferee.
- (d) When control of a utility is transferred to another entity, or the utility's name is changed, the utility which will afterwards operate under the certificate of public convenience and necessity shall file with the Commission a tariff adoption notice, shall post the tariff adoption notice in a prominent public place in each local office and principal place of business of the utility, and shall have the tariff adoption notice available for public inspection at each local office and principal place of business. Adoption notice forms are available from the Commission. The tariff adoption notice shall contain all of the following information:
- (I) the name, phone number, and complete address of the adopting utility;
  - (II) the name of the previous utility;
  - (III) the number of the tariff adopted and the description or title of the tariff adopted;
  - (IV) the number of the tariff after adoption and the description or title of the tariff after adoption; and

- (V) unless otherwise requested by the applying utility in its application, a statement that the adopting utility is adopting as its own all rates, rules, terms, conditions, agreements, concurrences, instruments, and all other provisions that have been filed or adopted by the previous utility.

**4105. Securities and Liens.**

- (a) Subject to the exception contained in paragraph (h) of this rule, a utility which either derives more than five percent of its consolidated gross revenues in Colorado as a public utility or derives a lesser percentage if its revenues are earned by supplying an amount of energy which equals five percent or more of Colorado's consumption shall file an application for Commission approval of any proposal to issue or to assume any security or to create a lien.
- (b) An application for the issuance or assumption of securities with a maturity of 12 months or more or to create a lien shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) all information required in paragraphs 4002(b) and 4002(c);
  - (II) the resolution of the applying utility's board of directors approving the issuance, or assumption of the securities or to create a lien, together with, as applicable and available, the proposed indenture requirements, the mortgage note, the amendment to the loan contract, and the contract for sale of securities or creation of a lien;
  - (III) a statement describing each short-term and long-term indebtedness outstanding on the date of the most recent balance sheet;
  - (IV) a statement describing the classes and amounts of capital stock authorized by the articles of incorporation and the amount by each class of capital stock outstanding on the date of the most recent balance sheet;
  - (V) a statement of capital structure showing common equity, long-term debt, preferred stock, if any, and pro forma capital structure on the date of the most recent balance sheet giving effect to the issuance of the proposed securities. Debt and equity percentages to total capitalization, actual and pro forma, shall be shown;
  - (VI) a statement of the amount and rate of dividends declared and paid, or the amount and year of capital credits assigned and capital credits refunded, during the previous four calendar years including the present year to the date of the most recent balance sheet;
  - (VII) a statement describing the type and amount of securities to be issued; the anticipated interest rate or dividend rate; the redemption or sinking fund provisions, if any; and, within ten days of their filing with the Securities and Exchange Commission, the registration statement, related forms, and preliminary prospectus filed with the Securities and Exchange Commission relating to the proposed issuance;
  - (VIII) a statement of proposed uses, including construction, to which the funds will be or have been applied and a concise statement of the need for the funds; and

- (IX) a statement of the estimated cost of financing.
- (c) For applications for the creation of a lien on the applying utility's property situated within the State of Colorado where the creation of the lien is not related to the issuance or assumption of a security, the application shall also include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
- (I) a description of the property which will be subject to the lien;
  - (II) the amount of the lien;
  - (III) the proposed use of the funds to be received from the lien;
  - (IV) the estimated cost for the creation of the lien;
  - (V) the anticipated duration of the lien;
  - (VI) the anticipated release date of the lien;
  - (VII) the retirement payment plan to release the lien;
  - (VIII) a description of how the applying utility will ensure that neither the creation of the lien nor the use of the proceeds will violate § 40-3-114, C.R.S.;
  - (IX) a statement that, for the duration of the lien, the applying utility will advise the Commission within ten days of any bankruptcy, foreclosure, or liquidation proceeding; and
  - (X) a statement that the applying utility will advise the Commission within ten days of any deviation from its lien retirement payment plan;
- (d) The Commission shall issue notice of the application, which shall set a ten-day intervention period and a hearing date.
- (e) Customer notice. Within three days after the filing of an application to issue or to assume a security, the applying utility shall publish notice of the filing of the application in a newspaper of general circulation. The notice shall include, in addition to the information required by subparagraphs 4002(d)(I) – (XII), the address of the applicant.
- (f) The applying utility shall file with the Commission the published notice and an affidavit of publication as soon as possible after the filing of the application. The Commission shall not grant the application without the notice and the affidavit of publication.
- (g) The Commission shall give priority to an application made pursuant to this rule and shall grant or deny the application within 30 days after filing, unless the Commission, for good cause shown, enters an order granting an extension and stating fully the facts necessitating the extension. The Commission shall approve or disapprove an application made pursuant to this rule by written order.

- (h) Pursuant to § 40-1-104, C.R.S., a utility may issue, renew, extend or assume liability on securities, other than stocks, with a maturity date of not more than 12 months after the date of issuance, whether secured or unsecured, without application to or order of the Commission provided that no such securities so issued shall be refunded, in whole or in part, by any issue of securities having a maturity of more than 12 months except on application to and approval of the Commission.
- (i) Any security requiring Commission approval, but issued or assumed without such approval, shall be void.

**4106. Flexible Regulation to Provide Jurisdictional Service Without Reference to Tariffs.**

- (a) A utility seeking authority to provide a jurisdictional service without reference to a tariff shall file an application pursuant to this rule. A utility cannot provide a jurisdictional service without reference to a tariff without authority from the Commission.
- (b) An application for flexible regulation to provide jurisdictional service without reference to tariffs shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) all information required in paragraphs 4002(b) and 4002(c);
  - (II) the name of the customer or potential customer;
  - (III) a description of the jurisdictional service or services which the applying utility seeks to provide to a customer or a potential customer;
  - (IV) a description of the manner in which the applying utility will provide the jurisdictional service or services if it contracts with a customer or potential customer;
  - (V) the facts (not in conclusory form) which the applying utility believes satisfy the requirements of § 40-3-104.3(1)(a), C.R.S.; and
  - (VI) a statement that the applying utility has provided, or will provide when available, the application and contract as required by paragraph 4106(c) of this rule.
- (c) The contract which is the subject of the application shall be filed when available with the Commission under seal pursuant to rules 1100 through 1102 and § 40-3-104.3(1)(b), C.R.S. The applying utility shall furnish the application and, when it is available, the contract, under seal, to the OCC. Unless the applying utility requests other treatment, the Commission and the OCC shall treat the contract as confidential. If the Commission grants a protective order preserving the confidentiality of the contents of an application, then the applying utility shall also furnish a non-confidential version of the application without the contract to any utility then providing service to the customer or potential customer.

- (d) The direct testimony and attachments to be offered at hearing shall accompany the application unless the applying utility believes that the application will be uncontested and unopposed. If an attachment is large or cumbersome, the applying utility shall file the attachment with the Commission; shall provide, for the benefit of the intervenors, the title of the attachment and a summary of the information contained in the attachment; and shall state the location (other than the Commission) at which parties may inspect the attachment.
- (e) Pre-filed testimony or attachments shall not be modified once filed unless the modification is to correct typographical errors or misstatements of fact or unless all parties to the proceeding agree to the modification. In the event a substantive modification is made without the agreement of all parties, the Commission may allow the modification only upon a showing of good cause. The Commission may consider the effect of the substantive modification as a basis for a motion to continue in order to allow the Commission staff or any other party a reasonable opportunity to investigate and, if necessary, to address the modification.
- (f) The Commission shall provide notice of the application. Any person desiring to intervene in a proceeding initiated pursuant to § 40-3-104.3, C.R.S., and this rule shall move to do so within five days of the date the Commission provides notice.
- (g) Within five days of receiving written notice of an intervention in a proceeding initiated pursuant to § 40-3-104.3, C.R.S., and this rule, the applying utility shall hand-deliver or otherwise provide to the intervenor a non-confidential version of the application and the applying utility's pre-filed testimony and attachments.
- (h) Unless the Commission orders otherwise, the applying utility shall publish notice of the application in a newspaper of general circulation within three days of the filing of the application.
- (i) In addition to the requirements of subparagraphs 4002(d)(I) – (XII), the notice provided by the applying utility shall contain the following information:
  - (I) the address of the applying utility;
  - (II) the name of the customer(s) or potential customer(s) involved;
  - (III) a statement that the identified customer(s) or potential customer(s) may have the ability to provide its/their own service or may have competitive alternatives available to it/them;
  - (IV) a general description of the jurisdictional services to be provided;
  - (V) a statement of where affected customers may call to obtain information concerning the application and;
  - (VI) a statement that anyone desiring to participate as a party must file a petition to intervene within five days from the date of Commission notice of the application and that the intervention must comport with the Commission's Rules Regulating Practice and Procedure.
- (j) Within three days of providing notice, the applying utility shall file with the Commission an affidavit showing proof of publication of notice.



- (k) On a case-by-case basis, the Commission may require the applying utility to provide additional information.
- (l) Should an application be filed which the Commission determines is not complete, the Commission or Commission staff shall notify the applying utility within seven days from the date the application is filed of the need for additional information. The applying utility may then supplement the application so that it is complete. Once the application is complete, the Commission will process the application, with all applicable timelines running from the date the application is completed.
- (m) The Commission shall issue an order approving or disapproving the application within the time permitted under § 40-3-104.3(1)(b), C.R.S.
- (n) At the time of any proceeding in which a utility's overall rate levels are determined, the Commission may require the utility to file a fully distributed cost method which segregates investments, revenues, and expenses associated with jurisdictional utility service provided pursuant to any contract approved under this rule 4106 from other regulated utility operations in order to ensure that jurisdictional utility service provided pursuant to contract is not subsidized by revenues from other regulated utility operations.
- (o) The applying utility shall provide final contract or other description of the price and terms of service as specified in § 40-3-104.3(1)(e), C.R.S.

**4107. [Reserved].**

**4108. Tariffs.**

- (a) A utility shall keep on file with the Commission the following documents pertaining to gas sales service and gas transportation service: its current Colorado tariffs, forms of contracts (including gas sales agreements), and those gas transportation service agreements which are not the same as the standard gas transportation service agreement contained in the utility's tariffs. These documents, unless filed under seal, shall be available for public inspection at the Commission and at the principal place of business of the utility.
- (b) All tariffs shall comply with rule 1210 of the Commission's Rules of Practice and Procedure.
- (c) Filing and contents of tariff.
  - (l) In addition to the requirements and contents in rule 1210, the following shall be included in a utility's tariff as applicable:
    - (A) a description of the minimum heating value for gas service as required by paragraph 4202(a);
    - (B) a description of testing methods for gas quality as required by paragraph 4202(f);
    - (C) interruption and curtailment criteria, policies, and implementation priorities, as required by rule 4203;

- (D) transportation service rates, terms, and conditions, as required by rule 4205;
- (E) the utility's transportation service request form as required by paragraph 4206(a);
- (F) information regarding the utility's meter testing equipment and facilities, scheduled meter testing, meter testing records, fees for meter testing upon request, and meter reading, as required by rules 4303, 4304, 4305, 4306, and 4309;
- (G) information regarding benefit of service transfer policies as required by paragraph 4401(c);
- (H) information regarding installment payment plans and other plans, as required by rule 4404;
- (I) information regarding collection fees or miscellaneous service charges, as required by subparagraph 4404(c)(VI) and (c)(VIII).
- (J) information regarding any after-hour restoration fees, as required by paragraph 4409(b); and
- (K) all other rules, regulations, and policies covering the relations between the customer and the utility.

**4109. New or Changed Tariffs.**

- (a) A utility shall file with the Commission any new or changed tariffs. No new or changed tariff shall be effective unless it is filed with the Commission and either is allowed to go into effect by operation of law or is approved by the Commission.
- (b) A utility shall use one of the following processes to seek to add a new tariff or to change an existing tariff:
  - (I) The utility may file the proposed tariff, including the proposed effective date, accompanied by an advice letter pursuant to rule 1210. The utility shall provide notice in accordance with rule 1206. If the Commission does not suspend the proposed tariff in accordance with rule 1305 prior to the tariff's proposed effective date, the proposed tariff shall take effect on the proposed effective date.
  - (II) The utility may file an application to implement a proposed tariff on less than 30-days' notice, accompanied by the proposed tariff, including the proposed effective date. The utility shall provide notice in accordance with rule 1207. The application shall include the information required in paragraphs 4002(b) and 4002(c); shall explain the details of the proposed tariff, including financial data if applicable; shall state the facts which are the basis for the request that the proposed tariff become effective on less than 30-days' notice; and shall identify any prior Commission action, in any proceeding, pertaining to the present or proposed tariff.

- (III) Unless the Commission orders otherwise, a utility shall be permitted to file new tariffs complying with an order of the Commission or updating adjustment clauses previously approved by the Commission on not less than two business days' notice. No additional notice beyond the tariff filing itself shall be required.

**4110. Advice Letters.**

- (a) All advice letter filings shall comply with rule 1210 of the Commission's Rules of Practice and Procedure.
- (b) In addition to the requirements and contents in rule 1210, the advice letter shall include the estimated amounts, if any, by which the utility's revenues will be affected, calculated on an annual basis.
- (c) Customer notice of advice letter. If the utility is required by statute, Commission rule or order to provide notice to its customers of the advice letter, such notice shall include the requirements of subparagraphs 4002(d)(I) – (XII).

**4111. – 4199. [Reserved]**

**FACILITIES**

**4200. Construction, Installation, Maintenance, and Operation.**

The gas plant, equipment, and facilities of a utility shall be constructed, installed, inspected, maintained, and operated in accordance with accepted engineering and gas industry practices to assure continuity of service, uniformity in the quality of service, and the safety of persons and property.

**4201. Instrumentation.**

A utility purchasing natural gas energy or receiving natural gas energy for transportation services shall install, or shall require the interconnecting pipeline to provide, such instruments or meters as may be necessary to furnish information detailing the quantity and quality of gas received into its system as necessary to maintain measurement accuracy and acceptable gas quality.

**4202. Heating Value, Purity, and Pressure.**

- (a) A utility shall establish and maintain in its tariffs a minimum heating value for its gas, expressed in British Thermal Units per standard cubic foot. The minimum heating value shall be no less than the monthly average gross heating value of gas supplied by the utility in any given service area. No deviation below this minimum shall be permitted. The utility shall determine the heating value of gas by testing gas taken from such points on the utility's system and at such test frequencies as are reasonably necessary for a proper determination. The utility shall maintain records of tests conducted to determine the heating value of gas. The results of these tests shall be stated in terms of standard conditions.
- (b) A change in minimum heating value shall require an appropriate adjustment, if any, to rates.

- (c) The utility shall insure that the gas it supplies, if from multiple sources or if the supply from a single source changes in composition, is interchangeable for safe and efficient use. The utility shall insure that gas from new supply sources or from supply sources which the gas composition has changed is interchangeable with the gas it currently supplies. The utility shall evaluate interchangeability by means of one of the following:
  - (I) use of test results which establish that the gas supplied to the end-user falls within an acceptable range and which take into account the heating value, specific gravity, and composition of the gas;
  - (II) use of actual appliances to determine acceptability; or
  - (III) use of a standard in the natural gas industry.
- (d) A utility shall promptly readjust its customers' appliances and devices as necessary to render proper service if the readjustment is required for safe and efficient use in accordance with paragraph (c) of this rule. Unless otherwise ordered by the Commission, a readjustment made pursuant to this paragraph shall be done at no charge to the customer. If a utility determines that a readjustment pursuant to this paragraph is necessary, the utility shall notify the Commission, in writing, of the readjustment and of the reason for the readjustment.
- (e) A utility whose gas delivery exceeds 20 million cubic feet per annum shall test the heating value of gas at least once each week, unless the utility purchases or receives gas on a heat value basis or unless the interconnecting pipeline provides the utility with a record of the heating value of the gas delivered and the interconnecting pipeline's tests are made at least once each week.
- (f) All gas supplied to customers shall be substantially free of impurities which may cause corrosion of facilities or which may form corrosive or harmful fumes when burned in a properly-designed and properly-adjusted burner.
- (g) A LDC shall deliver gas at a pressure of six inches water column, plus or minus two inches water column, measured at the meter outlet, unless operating conditions require a higher delivery pressure. If a higher pressure is required, the utility shall require the customer to install appropriate pressure regulating equipment in the customer's lines, if necessary.
- (h) A utility shall monitor distribution pressure as follows:
  - (I) In a distribution system serving 100 or fewer customers, the utility shall semi-annually check distribution pressures by indicating gauges at the district regulator station or other appropriate point in the distribution system.
  - (II) In distribution system serving more than 100 and fewer than 500 customers, the utility shall provide at least one recording pressure gauge or telemetering pressure device at the pressure regulating station or at some other appropriate point in the distribution system.

(III) In a distribution system serving 500 or more customers, the utility shall maintain one or more additional recording pressure gauges or telemetering pressure devices and shall make frequent 24-hour records of the gas pressure prevailing at appropriate points in the system.

(i) In its tariff, a utility shall include a description of test methods, equipment, and frequency of testing used to determine the quality and pressure of gas service furnished.

**4203. Interruptions and Curtailments of Service.**

(a) A utility shall keep a record of all interruptions and curtailments of service on its entire system or on major divisions of its system, including a statement of the time, duration, and cause of each interruption or curtailment. A utility shall also keep a record of the time of starting up or shutting down of the compressing equipment and the period of operation of all regulators used for the maintenance of constant gas pressure.

(b) In its tariff a utility shall establish specific terms and conditions for interruptions and curtailments of service. The utility shall establish, and adhere to, interruption and curtailment priorities for sales service and for transportation service by customer class. These priorities shall be consistent with the requirements of this rule.

(c) A utility shall interrupt service within each class on an equitable basis, consistent with system constraints and its tariff. A utility shall interrupt service within a locale on a fair and reasonable basis, consistent with local conditions.

(d) A utility shall not make up any shortage by using the transportation customer's supplies without the transportation customer's consent.

(e) A utility shall curtail standby supply service to transportation customers who have contracted for standby supply service in accordance with the same system of class-by-class priorities as is applicable to sales customers established by the utility's tariffs.

(f) A utility may provide, under applicable sales tariffs, available supply service to gas transportation customers who have not purchased standby supply service from the utility and are experiencing supply shortages.

**4204. [Reserved].**

**4205. Gas Transportation Service Requirements.**

(a) In its tariffs, a utility shall establish maximum rates for gas transportation service. In addition, a utility which desires price flexibility shall include its minimum rates in its tariffs. The following apply to transportation tariff rates:

(I) Maximum rates for transportation shall be based on fully allocated cost methods and shall include an allowance for return on allocated rate base equal to the last rate of return authorized by the Commission for the utility.

- (II) A utility may, at its discretion, offer natural gas transportation standby capacity service or standby supply service. A utility may require separate charges for:
  - (A) natural gas transportation standby capacity (if offered);
  - (B) standby supply (if offered);
  - (C) administration, services and facilities; and
  - (D) a utility's avoidable purchased gas commodity costs based on current market-driven gas prices.
  
- (b) In its tariffs, a utility shall establish terms and conditions for gas transportation service, including at least the following:
  - (I) all criteria for determining gas transportation capacity;
  - (II) all gas transportation costs;
  - (III) all nomination requirements;
  - (IV) all measurement and facility requirements;
  - (V) as applicable, all gas supply cost provisions;
  - (VI) all gas balancing provisions;
  - (VII) all quality of gas requirements;
  - (VIII) the utility's line extension policy;
  - (IX) the gas transportation request form required by paragraph 4206(a);
  - (X) the utility's gas transportation standard gas transportation service agreement, which shall include the statements required by paragraph 4206(d); and
  - (XI) the utility's standard agency agreement required by paragraph 4206(e).

**4206. Gas Transportation Agreements.**

- (a) When a customer requests transportation service, a utility shall provide the customer requesting transportation with the utility's gas transportation form. This form shall set out clearly the information necessary for the utility to determine whether it can provide the requested transportation.
  
- (b) In determining whether capacity is available to provide the requested transportation, a utility shall take into account all conventional methods of delivering gas through its system, including without limitation forward haul, compression, exchange, flow reversal, backhaul, and displacement. The

utility is not required to perform exchanges or displacements over segments of its system which are not physically connected.

- (c) A utility shall process, shall approve or reject, and shall provide notification of its decision with respect to a transportation request within 60 days after receiving a written request from a transportation customer. If the utility rejects the request, the utility shall provide, within three business days, written notice of its decision to the customer and shall retain a record of the rejection notice for two years. The notice shall detail the reasons for the rejection and shall explain what changes are necessary to make the request acceptable. If the request is approved, the utility shall provide, within three business days, written notification of approval to the customer.
- (d) A utility shall maintain on file with the Commission a standard gas transportation agreement. All gas transportation agreements shall contain the following provisions.
  - (I) This agreement, and all its rates, terms and conditions as set out in this agreement and as set out in the tariff provisions which are incorporated into this agreement by reference, shall at all times be subject to modification by order of the Commission upon notice and hearing and a finding of good cause therefore. In the event that any party to this agreement requests the Commission to take any action which could cause a modification in the conditions of this agreement, the party shall provide written notice to the other parties at the time of filing the request with the Commission.
  - (II) If the end-use customer uses a marketing broker for nomination, gas purchases, and balancing, the end-use customer shall provide the utility with an agency agreement.
- (e) A utility shall maintain on file with the Commission the standard agency agreement to be used when an end-use transportation customer uses a third party for any services related to nomination, gas purchases, and balancing activities.
- (f) A utility shall maintain logs showing all requests for gas transportation. The log shall contain the following information: the identity of the party making the transportation request, the date of the request, the volume requirements, duration, receipt and delivery points, type of service, and the disposition of the request. The utility shall retain these logs for two years.

**4207. Purchases Replaced by Transportation.**

- (a) Any reduction of gas purchases by a current sales customer who replaces sales purchases with transportation directly reduces a utility's obligation to provide gas to that customer on both a peak day and on an annual volume basis. If offered by the utility, a customer may retain rights to gas supplies by electing to pay for standby capacity service and standby supply service.
- (b) Any reduction of gas purchases by a current interruptible sales customer who replaces said purchases with transportation gas directly reduces the utility's obligation to provide gas supplies to that customer on an annual volume basis. At the discretion of the utility, a customer may retain rights to interruptible gas supplies by electing to pay for standby supply service.

- (c) If a sales customer converts all, or a portion, of its service to transportation and if it does not elect standby supply service, then the customer must reapply for sales service in the future if it wishes to convert the transportation portion of its service back to sales service.
- (d) The utility shall have no sales service obligation to a transportation customer who is solely responsible for procuring its own gas supply. The customer may retain rights to gas supplies by electing to pay for standby supply service.

**4208. Anticompetitive Conduct Prohibited.**

- (a) A utility shall apply all transportation rates and policies without undue discrimination or preference to its affiliates. Each contract to transport gas for a marketing or brokering affiliate of a utility shall be an arm's-length agreement containing only terms which are available to other transportation customers.
- (b) A utility is prohibited from engaging in anticompetitive conduct, discriminatory behavior, and preferential treatment in transporting gas, including (without limitation) the following:
  - (I) disclosure to a marketing or brokering affiliate of confidential information provided by nonaffiliated transportation customers;
  - (II) disclosing to any transportation customer the utility's own confidential information unless the same information is communicated contemporaneously to all current transportation customers;
  - (III) disclosing to any transportation customer of information filed with a transportation request unless the same information is communicated contemporaneously to all current transportation customers;
  - (IV) providing any false or misleading information, or failing to provide information, regarding the availability of capacity for transportation service;
  - (V) tying an agreement to release gas to an agreement by the transportation customer to obtain services from a marketing or brokering affiliate of the utility or to an offer by the utility to provide or to expedite transportation service to its affiliate for the released gas;
  - (VI) providing any false or misleading information, or failing to provide information, about gas releases;
  - (VII) failing to notify all affiliate brokers and marketers and all transportation customers of gas releases at the same time and in the same manner or otherwise allowing marketing or brokering affiliates preferential access to released gas;
  - (VIII) lending gas to a marketing or brokering affiliate to meet balancing requirements except under terms available to other transportation customers;
  - (IX) directing potential customers to the utility's own marketing or brokering affiliate, but the utility may provide a list of all registered gas marketers and brokers, including its affiliates;



- (X) charging lower rates to a transportation customer conditioned on the purchase of gas from the utility's marketing or brokering affiliate;
- (XI) conditioning the availability of transportation service upon the use of the utility's marketing or brokering affiliate;
- (XII) providing exchange or displacement services to one transportation customer without providing them to others on the same terms and conditions;
- (XIII) giving its marketing affiliate preference over nonaffiliated customers in matters relating to transportation including, but not limited to, scheduling, balancing, transportation, storage, or curtailment priority;
- (XIV) disclosing to its affiliate any information the utility received from a nonaffiliated transportation customer or potential nonaffiliated transportation customer;
- (XV) failing contemporaneously to provide identical gas transportation sales or marketing information it provides to a marketing affiliate to all potential transportation customers, affiliated and nonaffiliated, on its system; and
- (XVI) failing to make available to all similarly-situated nonaffiliated transportation customers discounts which are comparable to those made to an affiliated marketer.

**4209. [Reserved].**

**4210. Line Extension.**

- (a) A utility shall have tariffs which set out its line extension policies, procedures, and conditions.
- (b) In its tariff a LDC shall include the following provisions for gas main extensions and service lateral extensions from its distribution system:
  - (I) the terms and conditions, by customer class, under which an extension will be made;
  - (II) provisions requiring the utility to provide to a customer or to a potential customer, upon request, service lateral connection information necessary to allow the customer's or potential customer's facilities to be connected to the utility's system;
  - (III) provisions requiring the utility to exercise due diligence in providing the customer or potential customer with an estimate of the anticipated cost of a connection or extension; and
  - (IV) provisions addressing steps to ameliorate the rate and service impact upon existing customers, including stating in the tariff the procedures by which future customers would share costs incurred by the initial or existing customers served by a connection or extension (as, for example, by including the procedures by which a refund of customer connection or extension payments would be made when appropriate).

**4211. – 4299. [Reserved].**

## **METERS**

### **4300. Service Meters and Related Equipment.**

- (a) All meters used in connection with gas metered service for billing purposes shall be furnished, installed, and maintained by the utility.
- (b) All equipment, devices, or facilities (including, without limitation, service meters) furnished by the utility and which the utility maintains and renews shall remain the property of the utility and may be removed by it at any time after discontinuance of service.
- (c) Each service meter shall indicate clearly the cubic feet or other units of service for which the customer is charged for service through each meter. In cases in which the dial reading of a meter, other than an orifice or other chart type meter, must be multiplied by a constant or factor to obtain the units consumed, the factor, factors, or constant shall be clearly marked on the dial or face of the meter, if possible. In the alternative, the constant, constants, or factor, or the method of calculating the constant, constants, or factor, shall be stated clearly on a customer's bill, with step by step instructions to allow customer to convert the unit of measurement from the dial of the meter to the billing unit or billing determinant on the bill.

### **4301. Location of Service Meters.**

- (a) As of the time of installation, meters shall be located in accordance with the pertinent utility tariffs and in accordance with accepted safe practice and gas utility industry standards.
- (b) As of the time of installation, meters shall be located so as to be easily accessible for reading, testing, and servicing in accordance with accepted safe practice and in accordance with gas utility industry standards.

### **4302. Service Meter Accuracy.**

- (a) Before being installed for use by a customer, every gas service meter, whether new, repaired, or removed from service for any cause shall be in good order and, except as provided in paragraph (b) of this rule, shall be adjusted to be correct to within one percent when passing gas at 20 percent of its rated capacity at one-half inch water column differential.
- (b) New rotary displacement type gas service meters in sizes having a rated capacity of more than 5,000 cubic feet per hour at a differential not to exceed two inches water column shall be tested and calibrated at the factory in accordance with recognized and accepted practices. These meters shall also be adjusted to be correct within two percent slow and one percent fast when passing gas at ten percent of its rated capacity and shall be adjusted to be correct within one percent slow and one percent fast when passing gas at 100 percent of its rated capacity. Prior to reuse of a rotary displacement type meter that has been removed from service, the meter shall pass the same testing criteria as a new meter.

### **4303. Meter Testing Equipment and Facilities.**

- (a) A utility shall provide, or shall arrange for a qualified third party to provide, such equipment and facilities as may be necessary to make the tests and to provide the service required. Such

equipment and facilities shall be available at all reasonable times for inspection by Commission staff.

- (b) A utility having more than 200 meters in service shall maintain, or shall require the qualified third party that provides meter testing equipment and facilities to maintain, suitable gas meter testing equipment in proper adjustment so as to register the condition of meters tested within one-half of one percent. The utility shall have and shall maintain, for the testing equipment, necessary certificate(s) of calibration showing that the equipment has been tested with a standard certified by the National Institute of Standards and Technology or other laboratory of recognized standing.
- (c) In its tariff, a utility shall include a description of its meter testing equipment and of the methods employed to ascertain and to maintain accuracy of all testing equipment.
- (d) A utility shall keep records of certification and calibrations for all testing equipment required by this rule for the life of the equipment.

**4304. Scheduled Meter Testing.**

- (a) A utility shall test, or shall arrange for testing of, service meters in accordance with the schedule in this rule or in accordance with a sampling program approved by the Commission.
- (b) If it wishes to use a sampling program, a utility shall file an application to request approval of a sampling program. The application shall include:
  - (I) the information required by paragraphs 4002(b) and 4002(c);
  - (II) a description of the sampling program which the utility wishes to use. This description shall include, at a minimum the following:
    - (A) the type(s) of meters subject to the sampling plan;
    - (B) the frequency of testing;
    - (C) the procedures to be used for the sampling;
    - (D) the meter test method to be used;
    - (E) the accuracy of the testing and of the sampling plan;
    - (F) an explanation of the reason(s) for the requested sampling program; and
    - (G) an analysis which demonstrates that, with respect to assuring the accuracy of the service meters tested, the requested sampling program is at least as effective as the schedule in this rule.
- (c) Revisions to any portion of a sampling program approved pursuant to the procedure in paragraph (b) of this rule shall be accomplished by the filing of, and Commission approval of, a new application.

- (d) Every service meter shall be tested and adjusted before installation to ensure that it registers accurately and conforms with the requirements of rule 4302. In addition, every service meter shall be tested on a periodic basis, as follows:
  - (I) diaphragm type gas service meter in sizes having rated capacity of 800 cubic feet or less per hour at one-half inch water column differential, every six years;
  - (II) diaphragm type gas service meter in sizes having a rated capacity of more than 800 cubic feet per hour at one-half inch water column differential, every five years;
  - (III) rotary displacement type gas service meter in sizes having a rated capacity of 5,000 cubic feet or less per hour at one-half inch water column differential, every five years;
  - (IV) rotary displacement type gas service meters in sizes having a rated capacity of more than 5,000 cubic feet per hour at a differential not to exceed two inches water column, the frequency of testing stated in the utility's tariff;
  - (V) orifice meters, not less than once each year; and
  - (VI) meter types not listed, not less than once each year.
- (e) In its tariff, a utility shall describe the utility's practices concerning the following:
  - (I) testing and adjustment of service meters at installation; and
  - (II) periodic testing after installation.

**4305. Meter Testing Upon Request.**

- (a) If a customer disputes the accuracy of a meter or disputes the billing that implicates the accuracy of a meter, the utility furnishing metered gas service shall inform the customer of their rights to have the meter tested as specified in this rule. Within 30 days of a customer's request, the utility shall test the meter's accuracy using standardized testing equipment. The test shall be conducted free of charge if the meter has not been tested within the previous 12 months; otherwise the utility may charge a fee for performing the test. The utility shall provide a written report of the test results to the customer and shall maintain the report on file for at least two years from the date of the test. If, upon completion of the test, the disputed meter is found to be inaccurate beyond the limits prescribed in rule 4302, it shall be deemed out of compliance.
- (b) Should a customer request and receive a meter test as prescribed in paragraph 4305(a) and continue to dispute the accuracy of the meter, or the billing that implicates the accuracy of the meter, the utility shall give notice to the customer of his or her right to request independent testing of the meter. The customer's right to request independent testing of the meter shall expire on the 30<sup>th</sup> day after the date of the utility's notice. Upon the customer's request, the utility shall make the disputed meter available for independent testing by a qualified meter testing facility of the customer's choosing. The customer is not entitled to take physical possession of the disputed meter. To be a qualified meter testing facility, the testing facility must be capable of testing the meter to meet all meter standards and requirements required by these rules.

- (c) If, upon completion of an independent test as prescribed in paragraph 4305(b), the disputed meter is found to be accurate within the limits of rule 4302, the customer shall bear all costs associated with conducting the independent test. If, upon completion of an independent test as prescribed in paragraph 4305(b), the disputed meter is found to be inaccurate beyond the limits prescribed in rule 4302, the meter shall be deemed out of compliance and the utility shall bear all costs associated with conducting the independent test.
- (d) In its tariff, a utility shall include any fees associated with customer-requested meter testing conducted within 12 months of a prior test.
- (e) If a meter is deemed out of compliance under this rule, the utility shall either inform the customer of his or her right to request a refund pursuant to rule 4402 or unilaterally issue the refund.

**4306. Records of Tests and Meters.**

- (a) For each meter owned or installed, a utility shall maintain a record showing the date of purchase, the manufacturer's serial number, the record of the present or previously installed location, and the date and results of the last test performed by the utility. This record shall be retained for the life of the meter plus 30 months.
- (b) Whenever a meter is tested either on request or upon complaint, the test record shall include the information necessary for identifying the meter, the reason for making the test, the reading of the meter if removed from service, the result of the test, and all data taken at the time of the test in a sufficiently complete form to permit the convenient checking of the methods employed and the calculations made. This record shall be retained for at least two years.

**4307- 4308. [Reserved].**

**4309. Meter Reading.**

- (a) Upon a customer's request, a utility shall provide written documentation showing the date of the most recent reading of the customer's meter and the total usage expressed in cubic feet or other unit of service recorded. On request, a utility supplying metered service shall explain to a customer in a clear non-technical statement its method of reading the customer's meter.
- (b) A utility shall include in its tariff a clear statement describing when meters will be read by the utility and the circumstances, if any, under which the customer must read the meter and submit the data to the utility. This statement shall specify in detail the procedure that the customer must follow and shall specify all special conditions that apply to each class of service.
- (c) Absent good cause, a utility shall read a meter monthly. For good cause shown, a utility shall read a meter at least once every six months.

**4310. – 4399. [Reserved]**

## **BILLING AND SERVICE**

### **4400. Applicability.**

Rules 4400 through 4412 apply to residential customers, small commercial customers and agricultural customers served pursuant to a LDC's rates or tariffs. Rules 4400 through 4405 and rules 4407 through 4412 shall not apply to customers served under a LDC's transportation rates or tariffs. In its tariffs, a LDC shall define "residential," "small commercial" and "agricultural" customers to which these rules apply. The LDC may elect to apply the same or different terms and conditions of service to other customers.

### **4401. Billing Information and Procedures.**

- (a) All bills issued to customers for metered service furnished shall show:
- (I) the dates and meter readings beginning and ending the period during which service was rendered;
  - (II) an appropriate rate or rate code identification for each separate rate component charged to the bill. Each component shall be designated on the bill in a manner such that the rate or charge can be identified clearly when referencing approved rates found in the utility's tariff;
  - (III) the net amount due for regulated charges;
  - (IV) the date by which payment is due, which shall not be earlier than 15 days after the mailing or the hand-delivery of the bill;
  - (V) a distinct marking to identify an estimated bill;
  - (VI) the total amount of all payments or other credits made to the customer's account during the billing period;
  - (VII) any past due amount. Unless otherwise stated in a tariff or Commission rule, an account becomes "past due" on the 31st day following the due date of current charges;
  - (VIII) the identification of, and amount due for, unregulated charges, if applicable;
  - (IX) any transferred amount or balance from any account other than the customer's current account; and
  - (X) all other essential facts upon which the bill is based, including factors and constants, as applicable.
- (b) A utility that bills for unregulated services or goods shall allocate partial payments first to regulated charges and then to unregulated charges or non-tariff charges and to the oldest balance due separately within each category.

- (c) A utility that transfers to a customer a balance from the account of a person other than that customer shall have in its tariffs the utility's benefit of service transfer policies and criteria. The tariffs shall contain an explanation of the process by which the utility will verify, prior to billing a customer under the benefit of service tariff, that the person to be billed in fact received the benefit of service.
- (d) A utility may transfer a prior unpaid debt to a customer's bill if the prior bill was in the name of the customer and the utility has informed the customer of the transferred amount and of the source of the unpaid debt (for example, and without limitation, the address of the premises to which service was provided and the period during which service was provided).
- (e) If it is offered in a tariff, upon request from a customer and where it is technically feasible, a utility may have the option to provide electronic billing (e-billing), in lieu of a printed bill, to the requesting customer. If a utility offers the option of e-billing, the following shall apply:
  - (I) the utility shall obtain the affirmative consent of a customer to accept such a method of billing in lieu of printed bills;
  - (II) the utility shall not charge a fee for billing through the e-billing option;
  - (III) the utility shall not charge a fee based on customer payment options that is different from the fee charged for the use of the same customer payment options by customers who receive printed bills; and
  - (IV) a bill issued electronically shall contain the same disclosures and Commission-required information as those contained in the printed bill provided to other customers.

**4402. Adjustments for Meter and Billing Errors.**

- (a) A utility shall adjust a customer's bill(s) for gas incorrectly metered or billed as follows.
  - (I) When, upon any meter accuracy test, a meter is found to be running slow in excess of error tolerance levels allowed under rule 4302, the utility may charge for one-half of the under-billed amount for the period dating from the discovery of the meter error back to the previous meter test, with such period not to exceed six months.
  - (II) When, upon any meter accuracy test, a meter is found to be running fast in excess of error tolerance levels allowed under rule 4302, the utility shall refund one-half of the excess charge for the period dating from the discovery of the meter error back to the previous meter test, with such period not to exceed two years.
  - (III) When a meter does not register, registers intermittently, or partially registers for any period, the utility may estimate, using the method stated in its tariff, a charge for the gas used based on amounts metered to the customer over a similar period in previous years. The period for which the utility charges the estimated amount shall not exceed six months.

- (IV) In the event of under-billings not provided for in subparagraph (a)(I) or (III) of this rule (such as, but not limited to, an incorrect multiplier, an incorrect register, or a billing error), the utility may charge for the period during which the under-billing occurred, with such period not to exceed six months.
- (V) In the event of over-billings not provided for in subparagraph (a)(II) of this rule, the utility shall refund for the period during which the over-billing occurred, with such period not to exceed two years.
- (b) The periods set out in paragraph (a) of this rule shall commence on the earliest date on which either the customer notifies the utility or the utility notifies the customer of a meter or billing error, the customer informs the utility of a billing or metering error, or a dispute based on a billing or metering error, or the customer submits an informal complaint to the Consumer Assistance Unit of the Commission. <http://www.colorado.gov/pacific/dora/file-consumer-complaint>.
- (c) In the event of an over-billing, the customer may elect to receive the refund as a credit to future billings or as a one-time payment. If the customer elects a one-time payment, the utility shall make the refund within 30 days. Such over-billings shall not be subject to interest.
- (d) In the event of under-billing, the customer shall be eligible and may elect to enter into a payment arrangement on the under-billed amount. The payment arrangement shall be equal in length to the length of time during which the under-billing occurred. Such under-billings shall not be subject to interest.

**4403. Applications for Service, Customer Deposits, and Third-Party Guarantee Arrangements.**

- (a) A utility shall process an application for utility service which is made either orally or in writing and shall apply nondiscriminatory criteria with respect to the requirement of a deposit prior to commencement of service.
- (b) If billing records are available for a customer who has received past service from the utility, the utility shall not require that person to make new or additional deposits to guarantee payment of current bills unless the records indicate recent or substantial delinquencies. All customers shall be treated without undue discrimination with respect to deposit requirements, and such requirements shall be specifically stated in to the utility's tariff.
- (c) A utility shall not require a deposit from an applicant for service who provides written documentation of a 12 consecutive month good credit history from the utility from which that person received similar service. For purposes of this paragraph, the 12 consecutive months must have ended no earlier than 60 days prior to the date of the application for service.
- (d) If a utility uses credit scoring to determine whether to require a deposit from an applicant for service or a customer, the utility shall have a tariff which describes, for each scoring model that it uses, the credit scoring evaluation criteria and the credit score limit which triggers a deposit requirement.
- (e) All utilities requiring deposits shall offer customers at least one non-cash alternative that does not require the use of the customer's social security number, in lieu of a cash deposit.



- (f) If a utility uses credit scoring, prior payment history with the utility, or customer-provided prior payment history with a like utility as a criterion for establishing the need for a deposit, the utility shall include in its tariff the specific evaluation criteria which trigger the need for a deposit.
- (g) If a utility denies an application for service or requires a deposit as a condition of providing service, the utility immediately shall inform the applicant for service of the decision and shall provide, within three business days, a written explanation to the applicant for service stating the specific reasons the application for service has been denied or a deposit is required.
- (h) No utility shall require any surety other than either a deposit to secure payment for utility services or a third-party guarantee of payment in lieu of a deposit. In no event shall the furnishing of utility services or extension of utility facilities, or any indebtedness in connection therewith, result in a lien, mortgage, or other interest in any real or personal property of the customer unless such indebtedness has been reduced to a judgment. Should the guarantor terminate service or terminate the third party guarantee before the customer has established a satisfactory payment record for 12 consecutive months, the utility, applying the criteria contained in its tariffs, may require a deposit or a new third party guarantor.
- (i) A deposit shall not exceed an amount equal to an estimated 90 days' bill of the customer, except in the case of a customer whose bills are payable in advance of service, in which case the deposit shall not exceed an estimated 60 days' bill of the customer. The deposit may be in addition to any advance, contribution in aid of construction or guarantee required by the utility tariff in connection with construction of lines or facilities, as provided in the extension policy in the utility's tariffs.
- (j) A utility receiving deposits shall maintain records showing:
  - (I) the name of each customer making a deposit;
  - (II) the amount and date of the deposit;
  - (III) each transaction, such as the payment of interest or interest credited, concerning the deposit;
  - (IV) each premise where the customer receives service from the utility while the deposit is retained by the utility;
  - (V) if the deposit was returned to the customer, the date on which the deposit was returned to the customer; and
  - (VI) if the unclaimed deposit was paid to the energy assistance organization, the date on which the deposit was paid to the energy assistance organization.
- (k) In its tariff, a utility shall clearly state its customer deposit policy for establishing or maintaining service. The tariff shall state the circumstances under which a deposit will be required and the circumstances under which it will be returned.

- (l) A utility shall issue a receipt to every customer from whom a deposit is received. No utility shall refuse to return a deposit or any balance to which a customer may be entitled solely on the basis that the customer is unable to produce a receipt.
- (m) The payment of a deposit shall not relieve any customer from the obligation to pay current bills as they become due. A utility is not required to apply any deposit to any indebtedness of the customer to the utility, except for utility services due or past due after service is terminated.
- (n) A utility shall pay simple interest on a deposit at the percentage rate per annum as calculated by the Commission staff and in the manner provided in this paragraph.
  - (I) At the request of the customer, the interest shall be paid to the customer either on the return of the deposit or annually. The simple interest on a deposit shall be earned from the date the deposit is received by the utility to the date the customer is paid. At the option of the utility, interest payments may be paid directly to the customer or credited to the customer's account.
  - (II) The simple interest to be paid on a deposit during any calendar year shall be at a rate equal to the average for the period October 1 through September 30 (of the immediately preceding year) of the 12 monthly average rates of interest expressed in percent per annum, as quoted for one-year United States Treasury constant maturities, as published in the Federal Reserve Bulletin, by the Board of Governors of the Federal Reserve System. Each year, the Commission staff shall compute the interest rate to be paid. If the difference between the existing customer deposit interest rate and the newly calculated customer deposit interest rate is less than 25 basis points, the existing customer deposit interest rate shall continue for the next calendar year. If the difference between the existing customer deposit interest rate and the newly calculated customer deposit interest rate is 25 basis points or more, the newly calculated customer deposit interest rate shall be used. The Commission shall send a letter to each utility stating the rate of interest to be paid on deposits during the next calendar year. Annually following receipt of Commission staff's letter, if necessary, a utility shall file by advice letter or application, as appropriate, a revised tariff, effective the first day of January of the following year, or on an alternative date set by the Commission, containing the new rate of interest to be paid upon customers' deposits, except when there is no change in the rate of interest to be paid on such deposits.
- (o) A utility shall have tariffs concerning third-party guarantee arrangements and, pursuant to those tariffs, shall offer the option of a third party guarantee arrangement for use in lieu of a deposit. The following shall apply to third-party guarantee arrangements:
  - (I) an applicant for service or a customer may elect to use a third-party guarantor in lieu of paying a deposit;
  - (II) the third-party guarantee form, signed by both the third-party guarantor and the applicant for service or the customer, shall be provided to the utility;
  - (III) the utility may refuse to accept a third-party guarantee if the guarantor is not a customer in good standing at the time of the presentation of the guarantee to the utility;

- (IV) the amount guaranteed shall not exceed the amount which the applicant for service or the customer would have been required to provide as a deposit;
  - (V) the guarantee shall remain in effect until the earlier of the following occurs:
    - (A) the guarantee is terminated in writing by the guarantor;
    - (B) if the guarantor was a customer at the time of undertaking the guarantee, the guarantor ceases to be a customer of the utility; or
    - (C) the customer has established a satisfactory payment record, as defined in the utility's tariffs, for 12 consecutive months.
  - (VI) Should the guarantor terminate service or terminate the third party guarantee before the customer has established a satisfactory payment record for 12 consecutive months, the utility, applying the criteria contained in its tariffs, may require a deposit or a new third party guarantor.
- (p) A utility shall pay all unclaimed monies, as defined in § 40-8.5-103(5), C.R.S., that remain unclaimed for more than two years to the energy assistance organization. "Unclaimed monies" shall not include undistributed refunds for overcharges subject to other statutory provisions and rules and credits to existing customers from cost adjustment mechanisms.
- (I) Monies shall be deemed unclaimed and presumed abandoned when left with the utility for more than two years after termination of the services for which the deposit or the construction advance was made or when left with the utility for more than two years after the deposit or the construction advance becomes payable to the customer pursuant to a final Commission order establishing the terms and conditions for the return of such deposit or advance and the utility has made reasonable efforts to locate the customer.
  - (II) Interest on a deposit shall accrue at the rate established pursuant to paragraph (n) of this rule commencing on the date on which the utility receives the deposit and ending on the date on which the deposit is paid to the energy assistance organization. If the utility does not pay the unclaimed deposit to the energy assistance organization within four months of the date on which the unclaimed deposition is deemed to be unclaimed or abandoned pursuant to subparagraph (p)(I) of this rule, then at the conclusion of the four-month period, interest shall accrue on the unclaimed deposit at the rate established pursuant to paragraph (n) of this rule plus six percent.
  - (III) If payable under the utility's line extension tariff provisions, interest on a construction advance shall accrue at the rate established pursuant to paragraph (n) of this rule commencing on the date on which the construction advance is deemed to be owed to the customer pursuant to the utility's extension policy and ending on the date on which the construction advance is paid to the energy assistance organization. If the utility does not pay the unclaimed construction advance to the energy assistance organization within four months of the date on which the unclaimed construction advance is deemed to be unclaimed or abandoned pursuant to subparagraph (p)(I) of this rule, then at the conclusion of the four-month period, interest shall accrue on the unclaimed construction advance at the rate established pursuant to paragraph (n) of this rule plus six percent.

- (q) A utility shall resolve all inquiries regarding a customer's unclaimed monies and shall not refer such inquiries to the energy assistance organization.
- (r) If a utility has paid unclaimed monies to the energy assistance organization, a customer later makes an inquiry claiming those monies, and the utility resolves the inquiry by paying those monies to the customer, the utility may deduct the amount paid to the customer from future funds submitted to the energy assistance organization.

**4404. Installment Payments.**

- (a) A utility shall make a budget or level payment plan available for its customers and have such plan clearly defined in its tariff.
- (b) A utility shall have in its tariff an installment payment plan which permits a customer to make installment payments if one of the following applies.
  - (I) The plan is to pay regulated charges from past billing periods and the past due amount arises solely from events under the utility's control (such as, without limitation, meter malfunctions, billing errors, utility meter reading errors, or failures to read the meter, except where the customer refuses to read the meter and it is not readily accessible to the utility). A utility shall advise a customer who is eligible for this type of plan of the customer's eligibility. At the request of the customer and at the customer's discretion, an installment payment plan under this subparagraph shall extend over a period equal in length to that during which the errors were accumulated and shall not include interest.
  - (II) The customer pays at least ten percent of the amount shown on the notice of discontinuance for regulated charges and enters into an installment payment plan on or before the expiration date of the notice of discontinuance.
  - (III) The customer pays at least ten percent of any regulated charges amount more than 30 days past due and enters into an installment payment plan on or before the last day covered by a medical certification. A customer who has entered into and failed to abide by an installment payment plan prior to receiving a medical certification shall pay all amounts that were due for regulated charges up to the date on which the customer presented a medical certification which meets the requirements of subparagraph 4407(e)(IV) and then may resume the installment payment plan.
  - (IV) If service has been disconnected, the customer pays at least any collection and reconnection charges and enters into an installment payment plan. This subparagraph shall not apply if service was discontinued because the customer breached a prior payment arrangement.
- (c) Installment payment plans shall include the following amounts that are applicable at the time the customer requests a payment arrangement:
  - (I) the unpaid remainder of amounts due for regulated charges shown on the notice of discontinuance;

- (II) any amounts due for regulated charges not included in the amount shown on the notice of discontinuance which have since become more than 30 days past due;
  - (III) all current regulated charges contained in any bill which is past due but is less than 30 days past the due date;
  - (IV) any new regulated charges contained in any bill which has been issued but is not past due;
  - (V) any regulated charges which the customer has incurred since the issuance of the most recent monthly bill;
  - (VI) any collection fees as provided for in the utility's tariff, whether or not such fees have appeared on a regular monthly bill;
  - (VII) any deposit, whether already billed, billed in part, or required by the utility's tariff, due for discontinuance or delinquency or to establish initial credit, other than a deposit required as a condition of initiating service; and
  - (VIII) any other regulated charges or fees provided in the utility's tariff (including without limitation miscellaneous service charges, investigative charges, and checks returned for insufficient funds charges), whether or not they have appeared on a regular monthly bill.
- (d) Within seven calendar days of entering into a payment arrangement with a customer, a utility shall provide the customer with this rule and a statement describing the payment arrangement. The statement describing the payment arrangement shall include the following:
- (I) the terms of the payment plan; and
  - (II) a description of the steps which the utility will take if the customer does not abide by payment plan.
- (e) Except as provided in subparagraph (b)(l) of this rule, an installment payment plan shall consist, at a minimum, of equal monthly installments for a term selected by the customer but not to exceed six months. In the alternative, the customer may choose a modified budget billing, level payment, or similar tariff payment arrangement in which the total due shall be added to the preceding year's total billing to the customer's premises, modified for any base rate or cost adjustment changes. The resulting amount shall be divided and billed in 11 equal monthly budget billing payments, followed by a settlement billing in the twelfth month, or shall follow other payment-setting practices consistent with the tariff plan available.

- (f) For an installment payment plan entered into pursuant to this rule, the first monthly installment payment, and with the new charges (unless the new charges have been made part of the arrangement amount) shall be due on a date which is not earlier than the next regularly-scheduled due date of the customer who is entering into the installment payment plan. Succeeding installment payments, together with the new charges, shall be due in accordance with the due date established in the installment payment plan. Any payment not made on the due date established in the installment payment plan shall be considered in default. Any new charges that are not paid by the due date shall be considered past due, excluding those circumstances covered in subparagraph (b)(I) of this rule.
- (g) This rule shall not be construed to prevent a utility from offering any other installment payment plan terms to avoid discontinuance or terms for restoration of service, provided the terms are at least as favorable to the customer as the terms set out in this rule.

**4405. Service, Rate, and Usage Information.**

- (a) In addition to the requirement found in rule 1206, a utility shall inform its customers of any change proposed or made in any term or condition of its service if that change or proposed change will affect the quality of the service provided.
- (b) A utility shall transmit information provided pursuant to this rule through the use of a method (such as, without limitation, bill inserts or periodic direct mail) that will assure receipt by each customer.
- (c) Upon request, a utility shall provide the following information to a customer.
  - (I) A clear and concise explanation of the existing rate schedule applicable to the customer, the rate components for that rate schedule, and an explanation of how those components are calculated and applicable to the customer. This shall be provided within ten days of a customer's request or, in the case of a new customer, within 60 days of the commencement of service.
  - (II) A clear and concise statement of the customer's actual consumption or degree-day adjusted consumption of gas for each billing period during the prior year, unless such consumption data are not reasonably ascertainable by the utility.
  - (III) A clear and concise explanation of the terms and conditions of service applicable to the customer.

**4406. Itemized Billing Components.**

- (a) A utility shall provide itemized gas cost information to all customers commencing with the first complete billing cycle in which the new rates are in effect. The information may be provided in the form of a bill insert or a separate mailing.
- (b) The information provided pursuant to this rule shall include the following:
  - (I) the per-unit and fixed service rates to be billed to the customer;

- II) the per-unit and monthly gas commodity costs for that customer;
- (III) the per-unit and monthly costs of upstream services for that customer; and
- (IV) the monthly gas demand side management costs for that customer.

**4407. Discontinuance of Service.**

- (a) A utility shall not discontinue the service of a customer for any reason other than the following:
  - (I) nonpayment of regulated charges;
  - (II) fraud or subterfuge;
  - (III) service diversion;
  - (IV) equipment tampering;
  - (V) safety concerns;
  - (VI) discontinuance ordered by any appropriate governmental authority; or
  - (VII) properly discontinued service being restored by someone other than the utility when the original cause for proper discontinuance has not been cured.
- (b) A utility shall not discontinue service for nonpayment of any of the following:
  - (I) any amount which has not appeared on a regular monthly bill or which is not past due. Unless otherwise stated in a tariff or Commission rule, an account becomes "past due" on the 31st day following the due date of current charges;
  - (II) any amount due on another account now or previously held or guaranteed by the customer, or with respect to which the customer received service, unless the amount has first been transferred either to an account which is for the same class of service or to an account which the customer has agreed will secure the other account. Any amount so transferred shall be considered due on the regular due date of the bill on which it first appears and shall be subject to notice of discontinuance as if it had been billed for the first time;
  - (III) any amount due on an account on which the customer is or was neither the customer of record nor a guarantor, or any amount due from a previous occupant of the premises. This subparagraph does not apply if the customer is or was obtaining service through fraud or subterfuge or if paragraph 4401(c) applies;
  - (IV) any amount due on an account for which the present customer is or was the customer of record, if another person established the account through fraud or subterfuge and without the customer's knowledge or consent;

- (V) any delinquent amount, unless the utility can supply billing records from the time the delinquency occurred;
  - (VI) any debt except that incurred for service rendered by the utility in Colorado; or
  - (VII) any unregulated charge.
- (c) If the utility discovers any connection or device installed on the customer's premises, including any energy-consuming device in the proximity of the utility's meter, which would prevent the meter from registering the actual amount of energy used, the utility shall do one of the following.
- (I) Remove or correct such devices or connections. If the utility takes this action, it shall leave at the premises a written notice which advises the customer of the violation, of the steps taken by the utility to correct it, and of the utility's ability to bill the customer for any estimated energy consumption not properly registered. This notice shall be left at the time the removal or correction occurs.
  - (II) Provide the customer with written notice that the device or connection must be removed or corrected within 15 days and that the customer may be billed for any estimated energy consumption not properly registered. If the utility elects to take this action and the device or connection is not removed or corrected within the 15 days permitted, then within seven calendar days from the expiration of the 15 days, the utility shall remove or correct the device or connection pursuant to subparagraph (c)(I) of this rule.
- (d) If a utility discovers evidence that any utility-owned equipment has been tampered with or that service has been diverted, the utility shall provide the customer with written notice of the discovery. The written notice shall inform the customer of the steps the utility will take to determine whether non-registration of energy consumption has or will occur and shall inform the customer that the customer may be billed for any estimated energy consumption not properly registered. The utility shall mail or hand-deliver the written notice within three calendar days of making the discovery of tampering or service diversion.
- (e) A utility shall not discontinue service, other than to address safety concerns, if one of the following is met:
- (I) If a customer at any time tenders full payment in accordance with the terms and conditions of the notice of discontinuance to a utility employee authorized to receive payment. Payment of a charge for a service call shall not be required to avoid discontinuance.
  - (II) If a customer pays, on or before the expiration date of the notice of discontinuance, at least one-tenth of the amount shown on the notice and enters into an installment payment plan with the utility, as provided in rule 4404.
  - (III) If it is between 12 Noon on Friday and 8 a.m. the following Monday; between 12 Noon on the day prior to and 8:00 a.m. on the day following any state or federal holiday; or between 12 Noon on the day prior to and 8:00 a.m. on the day following any day during which the utility's local office is not open.



- (IV) Medical emergencies.
- (A) A utility shall postpone discontinuance of gas service to a residential customer for 60 days from the date of a medical certificate issued by a Colorado-licensed physician or health care practitioner acting under a physician's authority which evidences that discontinuance of service will aggravate an existing medical emergency or create a medical emergency for the customer or a permanent resident of the customer's household. The customer may receive a single 30-day extension by providing a second medical certification prior to the expiration of the original 60-day period. A customer may invoke this subparagraph 4407(e)(IV)(A) only once in any twelve consecutive months.
  - (B) As a condition of obtaining a new installment payment plan on or before the last day covered by a medical certificate, a customer who had already entered into a payment arrangement, but had broken the arrangement prior to seeking a medical certification, may be required to pay all amounts that were due up to the date of the original medical certificate as a condition of obtaining a new payment arrangement. At no time shall a payment from the customer be required as a condition of honoring a medical certificate.
  - (C) The certificate of medical emergency shall be in writing, sent to the utility from the office of a licensed physician, and show clearly the name of the customer or individual whose illness is at issue; the Colorado medical identification number, phone number, name, and signature of the physician or health care practitioner acting under a physician's authority certifying the medical emergency. Such certification shall be incontestable by the utility as to the medical judgment, although the utility may use reasonable means to verify the authenticity of such certification.

**4408. Notice of Discontinuance.**

- (a) Except as provided in paragraphs (g) and (h) of this rule, a utility shall provide, by first class mail or by hand-delivery, written notice of discontinuance of service at least 15 days in advance of any proposed discontinuance of service. The heading shall contain, in bold font and capital letters, the following warning:
- THIS IS A FINAL NOTICE OF DISCONTINUANCE OF UTILITY SERVICE AND  
CONTAINS IMPORTANT INFORMATION ABOUT YOUR LEGAL RIGHTS AND  
REMEDIES. YOU MUST ACT PROMPTLY TO AVOID UTILITY SHUT OFF.**
- (b) The body of the notice of discontinuance under paragraph (a) of this rule shall at a minimum advise the customer of the following:
- (I) the reason for the discontinuance of service and of the particular terms of service and rule (if any) which has been violated;
  - (II) the amount past due for utility service, deposits, or other regulated charges, if any;

- (III) the date by which an installment payment plan must be entered into or full payment must be received in order to avoid discontinuance of service;
  - (IV) how and where the customer can pay or enter into an installment payment plan prior to the discontinuance of service;
  - (V) that the customer may avoid discontinuance of service by entering into an installment payment plan with the utility pursuant to rule 4404 as described in the utility's applicable tariff;
  - (VI) that the customer has certain rights if the customer or a member of the customer's household is seriously ill or has a medical emergency;
  - (VII) that the customer has the right to dispute the discontinuance directly with the utility by contacting the utility, and how to contact the utility toll-free from within the utility's service area;
  - (VIII) that the customer has the right to make an informal complaint to the Commission in writing, by telephone, or in person, along with the Commission's address and local and toll-free telephone number;
  - (IX) that the customer has the right to file a formal complaint, in writing, with the Commission pursuant to rule 1302 and that this formal complaint process may involve a formal hearing;
  - (X) that in conjunction with the filing of a formal complaint, the customer has a right to file a motion for a Commission order ordering the utility not to disconnect service pending the outcome of the formal complaint process and that the Commission may grant the motion upon such terms as it deems reasonable, including but not limited to the posting of a deposit or bond with the utility or timely payment of all undisputed regulated charges;
  - (XI) that if service is discontinued for non-payment, the customer may be required, as a condition of restoring service, to pay reconnection and collection charges in accordance with the utility's tariff; and
  - (XII) that qualified low-income customers may be able to obtain financial assistance to assist with the payment of the utility bill and that more detailed information on that assistance may be obtained by calling the utility toll-free. The utility shall state its toll-free telephone number.
- (c) At the time it provides notice of discontinuance to the customer, a utility shall also provide written notice by first class mail or hand-delivery to any third-party the customer has designated in writing to receive notices of discontinuance or broken arrangement.
- (d) A discontinuance notice shall be printed in English and a specific language or languages other than English where the utility's service territory contains a population of at least ten percent who speak a specific language other than English as their primary language as determined by the latest U.S. Census information.

- (e) A utility shall explain and shall offer the terms of an installment payment plan to each customer who contacts the utility in response to a notice of discontinuance of service.
- (f) Following the issuance of the notice of discontinuance of service, and at least 24 hours prior to discontinuance of service, a utility shall attempt to give notice of the proposed discontinuance in person or by telephone both to the customer and to any third party the customer has designated in writing to receive such notices. If the utility attempts to notify the customer in person but fails to do so, it shall leave written notice of the attempted contact and its purpose.
- (g) If a customer has entered into an installment payment plan and has defaulted or allowed a new bill to remain unpaid past its due date, a utility shall provide, by first class mail or by hand-delivery, a written notice to the customer. The notice shall contain:
  - (I) a heading as follows: NOTICE OF BROKEN ARRANGEMENT
  - (II) statements that advise the customer:
    - (A) that the utility may discontinue service if it does not receive the monthly installment payment within ten days after the notice is mailed or hand-delivered;
    - (B) that the utility may discontinue service if it does not receive payment for the current bill within 30 days after its due date;
    - (C) that, if service is discontinued, the utility may refuse to restore service until the customer pays all amounts for regulated service more than 30 days past due and any collection or reconnection charges; and
    - (D) that the customer has certain rights if the customer or a member of the customer's household is seriously ill or has a medical emergency.
- (h) A utility is not required to provide notice under this rule if one of the following applies:
  - (I) the situation involves safety concerns;
  - (II) discontinuance is ordered by any appropriate governmental authority;
  - (III) either paragraph 4407(c) or 4407(d) applies; or
  - (IV) service, having been already properly discontinued, has been restored by someone other than the utility and the original cause for discontinuance has not been cured.
- (i) Where a utility knows that the service to be discontinued is used by customers in multi-unit dwellings, in places of business, or in a cluster of dwellings or places of business and the utility service is recorded on a single meter used either directly or indirectly by more than one unit, the utility shall issue notice as required in paragraphs (a) and (b) of this rule, except that:
  - (I) the notice period shall be 30 days;
  - (II) such notice may include the current bill;

- (III) the utility shall provide written notice to each individual unit, stating that a notice of discontinuance has been sent to the party responsible for the payment of utility bills for the unit and that the occupants of the units may avoid discontinuance by paying the next new bill in full within 30 days of its issuance and successive new bills within 30 days of issuance; and
- (IV) the utility shall post the notice in at least one of the common areas of the affected location.

**4409. Restoration of Service.**

- (a) Unless prevented from doing so by safety concerns, a utility shall restore, without additional fee or charge, any discontinued service which was not properly discontinued or restored as provided in rules 4407, 4408, and 4409.
- (b) Unless prevented by safety concerns, a utility shall restore service within 24 hours (excluding weekends and holidays), or within 12 hours if the customer pays any necessary after-hours charges established in tariffs, if the customer does any of the following:
  - (I) pays in full the amount for regulated charges shown on the notice and any deposit and/or fees as may be specifically required by the utility's tariff in the event of discontinuance of service;
  - (II) pays any reconnection and collection charges specifically required by the utility's tariff, enters into an installment payment plan, and makes the first installment payment, unless the cause for discontinuance was the customer's breach of such an arrangement;
  - (III) presents a medical certification, as provided in subparagraph 4407(e)(IV);
  - (IV) demonstrates to the utility that the cause for discontinuance, if other than non-payment, has been cured.

**4410. Refunds.**

- (a) A utility shall file an application for Commission approval of a refund plan if it seeks to refund monies of an amount that exceeds one half of one percent of the utility's prior year's total gross revenues as reported to the Commission in its most recent annual report. The utility may refund amounts to the appropriate customers or classes of customers of less than one half of one percent of the utility's prior year's gross revenues without Commission approval; however, such refunds are required to be noted in the utility's annual report when filed with the Commission pursuant to paragraph 4006(a).
- (b) The application for approval of a refund plan shall include, in the following order and specifically identified, the following information either in the application or in the appropriately identified attachments:
  - (I) all the information required in paragraphs 4002(b) and 4002(c);
  - (II) the reason for the proposed refund;

- (III) a detailed description of the proposed refund plan, including the type of utility service involved, the service area involved, the class(es) of customers to which the refund will be made, and the dollar amount (both the total amount and the amount to be paid to each customer class) of the proposed refund. The interest rate on the refund shall be the current interest rate in the applying utility's customer deposits tariff;
  - (IV) the date the applying utility proposes to start making the refund, which shall be no more than 60 days after the filing of the application; the date by which the refund will be completed; and the means by which the refund is proposed to be made;
  - (V) if applicable, a reference (by proceeding number, decision number, and date) to any Commission decision requiring the refund or, the order itself if the refund is to be made because of receipt of monies by the applying utility under the order of a court or of another state or federal agency;
  - (VI) a statement describing in detail the extent to which the applying utility has any financial interest in any other company involved in the refund plan;
  - (VII) a statement showing accounting entries under the Uniform System of Accounts; and
  - (VIII) a statement that, if the application is granted, the applying utility will file an affidavit verifying that the refund has been made in accordance with the Commission's decision.
- (c) A utility shall pay 90 percent of all undistributed balances, plus associated interest, to the energy assistance organization. For purposes of this rule, a refund is deemed undistributed if, after good faith efforts, a utility is unable to find the person entitled to a refund within the period of time fixed by the Commission in its decision approving the refund plan.
- (d) A utility shall pay an undistributed refund to the energy assistance organization within four months after the refund is deemed undistributed. A utility shall pay interest on an undistributed refund from the time it receives the refund until the refund is paid to the energy assistance organization. The interest rate shall be equal to the interest rate set by the Commission pursuant to paragraph 4403(m).
- (e) Whenever a utility makes a refund, it shall provide written notice to those customers that it believes may be master meter operators. The notice shall contain:
- (I) the definition of master meter operator, as set forth in these rules;
  - (II) a statement regarding a mater meter operator's obligation to do the following:
    - (A) to notify its end users of their right to claim, within 90 days, their proportionate share of the refund; and
    - (B) after 90 days, if the unclaimed balance exceeds \$100, to remit the unclaimed balance to the energy assistance organization.
- (f) A utility shall resolve all inquiries regarding a customer's undistributed refund and shall not refer such inquiries to the energy assistance organization.

- (g) If a utility has paid an undistributed refund to the energy assistance organization, a customer later makes an inquiry claiming that refund, and the utility resolves the inquiry by paying that refund to the customer, the utility may deduct the amount paid to the customer from future funds submitted to the energy assistance organization.

**4411. Low-Income Energy Assistance Act.**

- (a) Scope and applicability.
- (I) Rule 4411 is applicable to gas and combined gas and electric utility providers except those exempted under (II) or (III). Pursuant to §§ 40-8.7-101 through 111, C.R.S., utilities are required to provide an opportunity for their customers to contribute an optional amount through the customers' monthly billing statement.
- (II) Municipally owned gas or gas and electric utilities are exempt if:
- (A) the utility operates an alternative energy assistance program to support its low-income customers with their energy needs and self-certifies to the Organization through written statement that its program meets the following criteria:
- (i) the amount and method for funding of the program has been determined by the governing body; and
- (ii) the program monies will be collected and distributed in a manner and under eligibility criteria determined by the governing body for the purpose of residential energy assistance to customers who are challenged with paying energy bills for financial reasons, including seniors on fixed incomes, individuals with disabilities, and low-income individuals, or,
- (B) the governing body of the utility determines its service area has a limited number of people who qualify for energy assistance and self-certifies to the Organization via written statement such determination.
- (III) A municipally owned gas or gas and electric utility not exempt under subparagraph (a)(II) of this rule, is exempt if:
- (A) the utility designs and implements a procedure to notify all customers at least twice each year of the option to conveniently contribute to the Organization by means of a monthly energy assistance charge. Such procedure shall be approved by the governing utility. The governing body of such utility shall determine the disposition and delivery of the optional energy assistance charge that it collects on the following basis:
- (i) delivering the collections to the organization for distribution; or
- (ii) distributing the moneys under criteria developed by the governing body for the purpose set forth in subparagraph (a)(II)(A)(ii) of this rule;

- (B) alternatively, the utility provides funding for energy assistance to the Organization by using a source of funding other than the optional customer contribution on each customer bill that approximates the amount reasonably expected to be collected from an optional charge on customer's bills.
  - (IV) A municipally gas or gas and electric utility that is exempt under subparagraph (a)(III) of this rule shall be entitled to participate in the Organization's low-income assistance program.
  - (V) Gas or gas and electric utilities that desire a change in status must inform the Organization and file a notice to the Commission within 30 days prior to expected changes.
- (b) Definitions. The following definitions apply only in the context of rule 4411. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.
- (I) "Alternative energy assistance program" means a program operated by a municipally owned electric and gas utility or rural electric cooperative that is not part of the energy assistance program established pursuant to this statute.
  - (II) "Customer" means the named holder of an individually metered account upon which charges for electricity or gas are paid to a utility. "Customer" shall not include a customer that receives electricity or gas for the sole purpose of reselling the electricity or gas to others.
  - (III) "Energy assistance program" or "Program" means the Low Income Energy Assistance Program created by § 40-8.7-104, C.R.S., and designed to provide financial assistance, residential energy efficiency, and energy conservation assistance.
  - (IV) "Organization" means Energy Outreach Colorado, a Colorado nonprofit corporation.
  - (V) "Remittance device" means the section of a customer's utility bill statement that is returned to the utility company for payment. This includes but is not limited to paper payment stubs, web page files used to electronically collect payments, and electronic fund transfers.
  - (VI) "Utility" means a corporation, association, partnership, cooperative electric association, or municipally owned entity that provides retail electric service or retail gas service to customers in Colorado. "Utility" does not mean a propane company.
- (c) Plan implementation and maintenance.
- (I) Except as provided in paragraph 4411(a), each utility shall implement and maintain a customer opt-in contribution mechanism. The utility's opt-in mechanism shall include, at minimum, the following provisions.
    - (A) A description of the procedures the utility will use to notify its customers, including those customers that make payments electronically, about the opt-in provision. Utilities may combine their efforts to notify customers into a single

state-wide or region-wide effort consistent with the participating utilities communication programs. Each participating utility shall clearly identify its support of the combined communications program, with its corporate name and/or logo visible to the intended audience.

- (B) A description of the additional efforts the utility will use to inform its customers about the program to ensure that adequate notice of the opt-in provision is given to all customers. Notification shall include communication to all customers that the donation and related information will be passed through to the Organization.
- (C) A description of the check-off mechanism that will be displayed on the monthly remittance device to solicit voluntary donations. The remittance device shall include, at minimum, check-off categories of five dollars, ten dollars, twenty dollars, and “other amount”. The remittance device must also note the name of the program as the “voluntary energy assistance program,” or if the utility is unable to identify the name of the program individually, the utility shall use a general energy assistance identifier approved by the Commission.
- (D) A description or an example of how the utility will display the voluntary contribution as a separate line item on the customer’s monthly billing statement and how the voluntary contribution will be included in the total amount due. The line item must identify the contribution as “voluntary”.
- (E) A description of the notification process that the utility will use to ensure that once a utility customer opts into the program, the energy assistance contribution will be assessed on a monthly basis until the customer notifies the utility of the customer’s desire to stop contributing. The utility shall describe how it will manage participation in the program when customers miss one or more voluntary payment, or pay less than the pre-selected donation amount.
- (F) Identification of the procedures the utility will use to notify customers of their ability to cancel or discontinue voluntary contributions along with a description of the mechanism the utility will use to allow customers who make electronic payments to discontinue their participation in the opt-in program.
- (G) A description of the procedures the utility will use, where feasible, to notify customers participating in the program about the customer’s ability to continue to contribute when the customer changes their address within the utility’s service territory.
- (H) A description of the method the utility will use to provide clear, periodic, and cost-effective notice of the opt-in provision to its customers at least twice per year. Acceptable methods include, but are not limited to, bill inserts, statements on the bill or envelope, and other utility communication pieces.
- (I) A description of the start-up costs that the utility incurred in connection with the program along with supporting detailed justification for such costs. The description should include the utility’s initial costs of setting up the collection mechanism and reformatting its billing systems to solicit the optional contribution



but shall not include the cost of any notification efforts by the utility. Utilities may elect to recover all start-up costs before the remaining moneys generated by the program are distributed to the Organization or over a period of time from the funds generated by the program, subject to Commission review and approval.

- (J) An estimate of the on-going costs that the utility expects to incur in connection with the program along with supporting detailed justification for such costs. This estimate shall not include the cost of any notification efforts by the utility.
  - (K) A detailed justification for the costs identified in (I) and (J). As stated in § 40-8.7-104(3), C.R.S., the costs incurred must be reasonable in connection with the program.
  - (L) Utilities shall recover the start up cost and on-going cost of administration associated with the program from funds generated from the program. Insert and notification costs shall be considered in the utility's cost of service.
  - (M) A description of the procedures the utility will use to account for and process program donations separately from customer payments for utility services.
- (II) Each utility shall participate in the energy assistance program consistent with its plan approved by the Commission and shall provide the opportunity for its customers to make an optional energy assistance contribution on the monthly remittance device on their utility bill.
  - (III) The utility may submit an application to the Commission no later than April 1 of each year for approval of reimbursement costs the utility incurred for the program during the previous calendar year. Such application shall include a proposed schedule for the reimbursement of these costs to the utility. The applications shall include detailed supporting justification for approval of these costs. Such detailed justification includes, but is not limited to, copies of invoices and time sheets. Such applications shall not seek reimbursement of costs related to notification efforts. Participating utilities may request reimbursement costs for such notification efforts in base rate filings, subject to Commission review and approval.
  - (IV) A utility may seek modification of its initial plan or subsequent plans by filing an application with the Commission.
- (d) Fund administration.
- (I) At a minimum, each utility shall transfer the funds collected from its customers under the energy assistance program to the organization under the following schedule:
    - (A) for the funds collected during the period of January 1 to March 31 of each year, the utility shall transfer the collected funds to the Organization before May 1 of such year;

- (B) for the funds collected during the period of April 1 to June 30 of each year, the utility shall transfer the collected funds to the Organization before August 1 of such year;
  - (C) for the funds collected during the period of July 1 to September 30 of each year, the utility shall transfer the collected funds to the Organization before November 1 of such year;
  - (D) for the funds collected during the period of October 1 to December 31 of each year, the utility shall transfer the collected funds to the Organization before February 1 of the next year; and
  - (E) each utility shall maintain a separate accounting for all energy assistance program funds received by customers.
- (II) Each utility shall provide the organization with the following information.
- (A) How the funds collected for the previous calendar year were generated, including the number of customers participating in the program. Such report shall include a summary of the number of program participants and funds collected by month, and shall be provided by February 1 of each year.
  - (B) At each time funds are remitted, a listing of all program participants including the donor's name, billing address, and monthly donation amount. The participant information provided to the organization shall be used exclusively for complying with the requirements of § 40-8.7-101, C.R.S., et seq. and state and federal laws.
- (III) The Public Utilities Commission shall submit, as necessary, a bill for payment to the Organization for any administrative costs incurred pursuant to the program.
- (IV) The organization shall provide the Office of Consumer Counsel and the Public Utilities Commission with a copy of the written report that is described in § 40-8.7-110, C.R.S. This report shall not contain individual participant information.
- (e) Prohibition of disconnection. Utilities shall not disconnect a customer's gas service for non-payment of optional contribution amounts.

**4412. Gas Service Low-Income Program.**

- (a) Scope and applicability.
  - (I) Gas utilities with Colorado retail customers shall provide low-income energy assistance by offering rates, charges, and services that grant a reasonable preference or advantage to residential low-income customers, as permitted by § 40-3-106, C.R.S.
  - (II) Rule 4412 is applicable to investor-owned gas utilities subject to rate regulation by the Commission.

- (b) Definitions. The following definitions apply only in the context of rule 4412. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.
- (I) “Administrative cost” means the utility’s direct cost for labor (to include the cost of benefit loadings), materials, and other verifiable expenditures directly related to the administration and operation of the program not to exceed ten percent of the total cost of program credits applied against bills for current usage and pre-existing arrearages or \$10,000, whichever amount is greater.
  - (II) “Affordable percentage of income payment” means the amount of the participant’s annual bill deemed affordable under subparagraph 4412(e)(I).
  - (III) “Arrearage” means the past-due amount appearing, as of the date on which a participant newly enters the program, on the then most recent prior bill rendered to a participant for which they received the benefit of service.
  - (IV) “Colorado Energy Office” (CEO) means the Colorado Energy Office created in § 24-38.5-101, C.R.S.
  - (V) “Eligible low-income customer” means a residential utility customer who meets the household income thresholds pursuant to paragraph 4412(c).
  - (VI) “Fixed credit” means an annual bill credit established at the beginning of a participant’s participation in a program each year delivered as a monthly credit on each participant’s bill. The fixed credit is the participant’s full annual bill minus the participant’s affordable percentage of income payment obligation on the full annual bill.
  - (VII) “Full annual bill” means the current consumption of a participant billed at standard residential rates. The full annual bill of a participant is comprised of two parts: (1) that portion of the bill that is equal to the affordable percentage of income payment; and (2) that portion of the bill that exceeds the affordable percentage of income payment.
  - (VIII) “LEAP” means Low-Income Energy Assistance Program, a county-run, federally-funded, program supervised by the Colorado Department of Human Services, Division of Low-Income Energy Assistance.
  - (IX) “LEAP participant” means a utility customer who at the time of applying to participate in a program has been determined to be eligible for LEAP benefits by the Department during either the Department’s current six-month (November 1 – April 30) LEAP application period, if that period is open at the time the customer applies for program participation; or (the Department’s most recently closed six-month (November 1 – April 30) LEAP application period, if that period is closed at the time the customer applies to participate in the program and the Department’s next six-month (November 1 – April 30) LEAP application period has not yet opened, provided, however, that in order to retain status as a LEAP participant under this definition, the utility customer must apply to the Department during the Department’s next six-month (November 1 – April 30) LEAP benefit application period and be determined eligible for such benefits.

- (X) “Non-participant” means a utility customer who is not receiving low-income assistance under rule 4412.
  - (XI) “Participant” means an eligible low-income residential utility customer who is granted the reasonable preference or advantage through participation in a gas service low-income program.
  - (XII) “Percentage of Income Payment Plan” (PIPP) means a payment plan for participants that does not exceed an affordable percentage of their household income as set forth in subparagraph 4412(e)(I).
  - (XIII) “Program” means a gas service low-income program approved under rule 4412.
  - (XIV) “Program credits” means the amount of benefits provided to participants to offset the unaffordable portion of a participant’s utility bill and /or dollar amounts credited to participants for arrearage forgiveness.
  - (XV) “Unaffordable portion” means the amount of the estimated full annual bill that exceeds the affordable percentage of income payment.
- (c) Participant eligibility. Eligible participants are limited to those with a household income at or below 185 percent of the current federal poverty level, or, if the utility applies individual LEAP benefits to offset the costs of the unaffordable portion of the participating customer’s utility bill, the percent of the current federal poverty level set by the Colorado Department of Human Services, Division of Low-income Energy Assistance for eligibility in the LEAP program.
- (I) Gas utilities may obtain federal annual poverty level income amounts based on household size on the Colorado Department of Human Services, Division of Low Income Energy Assistance website at <https://sites.google.com/a/state.co.us/cdhs-leap/program-eligibility>.
  - (II) The utility shall obtain household income information from LEAP.
  - (III) If a participant’s household income is \$0, the utility may establish a process that verifies income on a more frequent basis.
  - (IV) Program participants shall not be required to make payment on their utility account as a condition of entering into the program.
- (d) Enrollment. Utilities shall be responsible for the methods by which participant enrollment in their approved low income program is obtained and sustained, however the utility should engage in enrollment processes that are efficient and attempt to maximize the potential benefits of participation in the low income program by low income customers.

- (e) Payment plan.
- (I) Participant payments for natural gas bills rendered to participants shall not exceed an affordable percentage of income payment. For accounts for which natural gas is the primary heating fuel, participant payments shall be no lower than two percent and not greater than three percent of the participant's household income.
  - (II) In the event that a primary heating fuel for any particular participant has been identified by LEAP, that determination shall be final.
  - (III) Notwithstanding the percentage of income limits established in subparagraph 4412(e)(I), a utility may establish minimum monthly payment amounts for participants with household income of \$0, provided that the participant's minimum payment for a natural gas account shall be no more than \$10.00 a month.
  - (IV) Full annual bill calculation. The utility shall be responsible for estimating a participant's full annual bill for the purpose of determining the unaffordable portion of the participant's full annual bill delivered as a fixed credit on the participant's monthly billing statement.
  - (V) Fixed credit benefit. The fixed credit shall be adjusted during a program year in the event that standard residential rates, including commodity or fuel charges change to the extent that the full annual bill at the new rates would differ from the full annual bill upon which the fixed credits are currently based by 25 percent or more.
  - (VI) Levelized budget billing participation. A utility shall enroll participants in its levelized budget billing program as a condition of participation in the program. Should a participant fail to meet monthly bill obligations and be placed by a utility in its regular delinquent collection cycle, the utility may remove the participant from levelized budget billing in accordance with the utility's levelized budget billing tariff.
  - (VII) Arrearage credits.
    - (A) Arrearage credits shall be applied to pre-existing arrearages.
    - (B) Arrearage credits shall be sufficient to reduce, when combined with participant copayments, if any, the pre-existing arrearages to \$0.00 over a period not less than one month and not more than twenty-four months.
    - (C) Application of an arrearage credit to a participant account may be conditioned by the utility on one or more of the following:
      - (i) the receipt of regular participant payments toward bills for current usage;  
or
      - (ii) the payment of a participant copayment toward the arrearages so long as the participant's copayment total dollar amount does not exceed one percent of gross household income.

- (D) Should the participant exit the program prior to the full forgiveness of all pre-existing arrearages, the amount of remaining pre-existing arrearages shall become due in accordance with the utilities tariff filed under rules 4401, 4407, and 4408.
  - (E) Pre-existing arrears under this subparagraph shall not serve as the basis for the termination of service for nonpayment or as the basis for any other utility collection activity while the customer is participating in the program.
  - (F) A participant may receive arrearage credits under this section even if that participant does not receive a credit toward current bills, if the participant enters into and maintains a levelized budget billing plan.
- (VIII) Portability of benefits. A participant may continue to participate without reapplication should the participant change service addresses, but remain within the service territory of the utility providing the benefit, provided that the utility may make necessary adjustments in the levelized budget billing amount to reflect the changed circumstances. A participant who changes service addresses and does not remain within the service territory of the utility providing the benefit must reapply to become a participant at the participant's new service address.
- (IX) Payment default provisions. Failure of a participant to make his or her monthly bill payments will result in a utility placing the participant in its regular collection cycle. Missed, partial or late payments shall not result in the removal of a participant from the program.
- (f) Program implementation.
- Each utility shall maintain effective terms and conditions in its tariffs on file with the Commission describing its low-income program.
- (g) Cost recovery.
- (I) Each utility shall include in its low income tariff terms and conditions how costs of the program will be recovered.
  - (II) Program cost recovery.
    - (A) Program cost recovery shall be based on a fixed monthly fee.
    - (B) The maximum impact on residential rates shall be no more than \$00.31 per month.
    - (C) In order to determine monthly rates applicable to rate classes other than residential, program costs shall be allocated to each retail rate based on each rate class's share of the test year revenue requirement established in the utility's last Phase II rate case, or under another reasonable methodology supported by quantifiable information. The monthly rate per this subparagraph to be charged each rate schedule customer shall be clearly stated on a tariff sheet.

- (D) Utilities shall separately account for the cumulative program cost recovery and cumulative program and administrative costs to determine if the net of program cost recovery and program and administrative cost are in balance during the program year.
  - (i) Beginning October 31, 2018 and in each year thereafter, the utility shall file a report with the Commission in the most recent miscellaneous proceeding for annual low-income filings detailing the net difference between program cost recovery and program costs as of September 30 of each year.
    - (1) Should the net difference of program cost recovery over program costs be greater than 50 percent derived in (ii) above, either positive or negative, and the utility is not currently at the maximum impact for non-participants, the utility shall file with the Commission an advice letter and tariff pages seeking approval for the rates determined in subparagraph 4412(g)(II)(D) in order to bring the projected recovery in balance for the ensuing 12 month period. The revised Residential charge shall not exceed the maximum impact for non-participants in subparagraph 4412(g)(II)(C).
- (III) The following costs are eligible for recovery by a utility as program costs:
  - (A) program credits or discounts applied against bills for current usage;
  - (B) program credits applied against pre-existing arrearages;
  - (C) program administrative costs; and
  - (D) Commission-sponsored program evaluation costs required under paragraph 4412(k).
- (IV) The utility shall apply, as an offset to cost recovery, all program expenses attributable to the program. Program expenses include utility operating costs; changes in the return requirement on cash working capital for carrying arrearages; changes in the cost of credit and collection activities directly related to low-income participants; and changes in uncollectable account costs for these participants.
- (V) LEAP grants.
  - (A) The utility shall apply energy assistance grants provided to the participant by the LEAP program to the dollar value of credits granted to individual program participants.
  - (B) A utility shall apply any energy assistance benefit granted to the participant by LEAP to that portion of the program participant's full annual bill that exceeds the participant's affordable percentage of income payment.

- (C) If the dollar value of the energy assistance grant is greater than the dollar value of the difference between the program participant's full annual bill and the participant's affordable percentage of income payment, the dollar amount by which the energy assistance grant exceeds the difference will be applied:
    - (i) first, to any pre-existing arrearages that at the time of the energy assistance grant continues to be outstanding; and
    - (ii) second, to the account of the program participant as a benefit to the participant.
  - (D) No portion of an energy assistance or LEAP grant provided to a program participant may be applied to the account of a participant other than the participant to whom the energy assistance grant was rendered.
- (h) Other programs. In addition to the utility's low-income program, with Commission approval, a utility may offer other rate relief options to eligible households.
- (I) Other programs offered by the utility under rule 4412 must be intended to reach low-income households that do not substantially benefit from the provisions of the low-income program. Such programs may take the form of discount rates, tiered discount rates or other direct bill relief methods where the low-income household benefitting from the program is granted a reasonable preference in tariffed rates assessed to all residential utility customers.
  - (II) Cost recovery for other programs combined with the Percentage of Income Payment Plan shall not exceed the maximum impact on residential rates described in subparagraph 4412(g)(II)(C).
- (i) Energy efficiency and weatherization.
- (I) The utility shall provide all program participants with information on energy efficiency programs offered by the utility or other entities and existing weatherization programs offered by the state of Colorado or other entities.
  - (II) The utility shall provide the Colorado Energy Office with the name and service address of participant households for which annual natural gas usage exceeds 600 therms annually.
- (j) Stakeholder engagement. A utility shall conduct annual meetings with low-income stakeholders for the purpose of seeking solutions to issues of mutual concern and aligning program practices with the needs of customers and other stakeholders.
- (k) Program evaluation. A triennial evaluation of the program provisions under rule 4412 beginning in 2019 shall be undertaken in order to review best practices in similar low income assistance programs in existence in other regulatory jurisdictions, as well as evaluate operation of each utility's program for effectiveness in achieving optimum support being provided to low income participants. The evaluation shall also recommend modifications if available that improve the delivery of benefits to participants and increase the efficiency and effectiveness of each program as they exist at the point of evaluation.



- (I) Procurement of the third-party vendor that will perform the evaluation will be undertaken by the Colorado Energy Office. The CEO shall seek the involvement of interested stakeholders including, but not limited to, Commission staff, all Commission regulated electric and gas utilities, LEAP, the Office of Consumer Counsel, and Energy Outreach Colorado in the design of the requirements regarding study focus and final reporting.
  - (II) Approval of the third-party vendor shall be the responsibility of the Commission. The CEO shall file with the Commission in the most recent annual report proceeding, a request for approval of the contract of the vendor selected. The Commission shall review and act on the request within 30 days.
  - (III) \$00.0013 per customer per month shall be set aside by the utility starting in the 2016-2017 program year in order to cover the cost of the program evaluation described in paragraph 4412(k).
  - (IV) The dollars resulting from the \$00.0013 charge shall be recovered as a program cost under subparagraph 4412(g)(III).
  - (V) The evaluation will be filed by Commission staff in the most recent miscellaneous proceeding for annual low income filings.
  - (VI) Staff and the CEO will assess the individual utilities' deferred balances set aside for the program evaluation starting in 2019 at the conclusion of the third program year and each three years thereafter and will determine the amounts each utility is to remit to the third party evaluator based on the contractual terms approved by the Commission for the evaluation.
- (I) Annual report. No later than December 31, of each year the utility shall file a report in the most recent miscellaneous proceeding established by the Commission to receive annual low income filings using the form available on the Commission's website, based on the 12-month period ending October 31 containing the following information:
- (I) monthly information on the program including number of participants, amount of benefit disbursement, type of benefit disbursement, LEAP benefits applied to the unaffordable portion of participant's bills, administrative costs, and revenue collection;
  - (II) the number of applicants for the program;
  - (III) the number of applicants qualified for the program;
  - (IV) the number of participants;
  - (V) the average assistance provided, both mean and median;
  - (VI) the maximum assistance provided to an individual participant;
  - (VII) the minimum assistance provided to an individual participant;

- (VIII) total cost of the program and the average rate impact on non-participants by rate class, including impact based on typical monthly consumption of both its residential and small business customers;
- (IX) the number of participants that had service discontinued as a result of late payment or non-payment, and the amount of uncollectable revenue from participants;
- (X) an estimate of utility savings as a result of the implementation of the program (e.g., reduction in trips related to discontinuance of service, reduction in uncollectable revenue, etc.);
- (XI) the average monthly and annual total natural gas consumption in PIPP participants' homes;
- (XII) the average monthly and annual total natural gas consumption in the utility's residential customer's homes;
- (XIII) the number of program participants referred to the weatherization program;
- (XIV) a description of the ways in which the program is being integrated with existing energy efficiency of DSM programs offered by the utility;
- (XV) a description of the ways in which the program is being integrated with existing weatherization programs offered by the state of Colorado;
- (XVI) a description of program outreach strategies and metrics that illustrate the effectiveness of each outreach strategy;
- (XVII) the number of participants at the start of the program year that the utility removed for any reason, the number of potential participants rejected because of the existence of a cap on the program, the period of arrearage time from date participants became eligible and were granted arrearage forgiveness, and the number of participants who came back as eligible participants in the program year after being eligible in a prior program year and were provided arrearage credits in the program year; and
- (XVIII) a narrative summary of the utility's recommended program modifications based on report findings.

**4413. – 4499. [Reserved].**

## **UNREGULATED GOODS AND SERVICES**

### **4500. Overview and Purpose.**

The purpose of these rules is to establish cost assignment and allocation principles to assist the Commission in setting just and reasonable rates and to ensure that utilities do not use ratepayer funds to subsidize non-regulated activities, in accordance with § 40-3-114, C.R.S. In order to promote these purposes, these rules also specify information that utilities must provide to the Commission. In providing for review of a utility's specific cost allocations in other states and jurisdictions, the rules merely

contemplate a methodology to allow interested parties to obtain complete information regarding cost allocations. These rules do not expressly or implicitly allow this Commission to order a utility to revise its cost allocations in other jurisdictions or states.

**4501. Definitions.**

The following special definitions apply only to rules 4501 through 4505. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- (a) “Activity” means a business activity, product or service whether offered by a Colorado utility, a division of a Colorado utility, or an affiliate of a Colorado utility.
- (b) “Allocate” or “Allocated” or “Cost Allocation” means to distribute a joint or common cost to or from more than one activity or jurisdiction.
- (c) “Assigned Costs” or “Cost Assignment” means a cost that is specifically identified with a particular activity or jurisdiction and charged directly to that activity or jurisdiction. At no point in the process of making the cost assignment is an allocation applied.
- (d) “Cost Assignment and Allocation Manual” (CAAM) means the indexed document filed by a utility with the Commission that describes and explains the cost assignment and allocation methods the utility uses to segregate and account for revenues, expenses, assets, liabilities, and rate base cost components assigned or allocated to Colorado jurisdictional activities. It includes the cost assignment and allocation methods to segregate and account for costs between and among jurisdictions, between regulated and non-regulated activities, and between and among utility divisions.
- (e) “Division” means an activity conducted by a Colorado utility but not through a legal entity separate from the Colorado utility. It includes the electric, gas, or thermal activities of a Colorado utility and any non-regulated activities provided by the Colorado utility.
- (f) “Fully Distributed Cost” (FDC) means the process of segregating, assigning, and allocating the revenues, expenses, assets, liabilities and rate base amounts recorded in the utility’s accounting books and records using cost accounting, engineering, and economic concepts, methods and standards. Fully distributed cost includes a return on investment in cases where assets are used.
- (g) “Fully Distributed Cost Study” is a cost study that reflects the result of the fully distributed revenues, expenses, assets, liabilities and rate base amounts for the Colorado utility to and from the different activities, jurisdictions, divisions, and affiliates using cost accounting, engineering, and economic concepts, methods, and standards.
- (h) “Incidental Services” means non-tariff or non-regulated services that have traditionally been offered incidentally to the provisions of tariff services where the revenues for all such services do not exceed:
  - (l) The greater of \$100,000 or one percent of the provider’s total annual Colorado operating revenues for regulated services; or,

- (II) Such amount established by the Commission considering the nature and frequency of the particular service.
- (i) “Jurisdictional” means having regulatory rate authority over a utility. Jurisdiction can be at a state or federal level.
- (j) “Regulated activity” means any activity that is offered as a public utility service as defined in Title 40, Articles 1 to 7 C.R.S., and is regulated by the Commission or regulated by another state utility commission or the FERC, or any non-regulated activity which meets the criteria specified in rules 4502(g).
- (k) “Non-regulated activity” means any activity that is not offered as a public utility service as defined in Title 40, Articles 1 to 7, C.R.S., and is not regulated by this Commission or another state utility commission or the FERC.
- (l) “Transaction” means the activity that results in the provision of products, services, or assets by one division or an affiliate to another division or an affiliate.

**4502. Cost Assignment and Allocation Principles.**

In determining fully distributed cost, the utility shall apply the following principles (listed in descending order of required application in paragraphs 4502 (a), (b) and (c) below).

- (a) Tariff services provided to an activity will be charged to the activity at the tariff rates.
- (b) If only one activity or jurisdiction causes a cost to be incurred, that cost shall be directly assigned to that activity or jurisdiction.
- (c) Costs that cannot be directly assigned to either regulated or non-regulated activities or jurisdictions will be described as common costs. Common costs shall be grouped into homogeneous cost categories designed to facilitate the proper allocation of costs between regulated and non-regulated activities or jurisdictions. Each cost category shall be fairly and equitably allocated between regulated and non-regulated activities or jurisdictions in accordance with the following principles.
  - (I) Cost causation. All activities or jurisdictions that cause a cost to be incurred shall be allocated a portion of that cost. Direct assignment of a cost is preferred to the extent that the cost can easily be traced to the specific activity or jurisdiction.
  - (II) Variability. If the fully distributed cost study indicates a direct correlation exists between a change in the incurrence of a cost and cost causation, that cost shall be allocated based upon that relationship.
  - (III) Traceability. A cost may be allocated using a measure that has a logical or observable correlation to all the activities or jurisdictions that cause the cost to be incurred.
  - (IV) Benefit. All activities or jurisdictions that benefit from a cost shall be allocated a portion of that cost.

- (V) Residual. The residual of costs left after either direct or indirect assignment or allocation shall be allocated based upon an appropriate general allocator to be defined in the utility's CAAM.
- (d) For cost assignment and allocation purposes, the value of all transactions from the Colorado utility to a non-regulated activity shall be determined as follows:
- (I) if the transaction involves a product or service provided by the utility pursuant to tariff, the value of the transaction shall be at the tariff rate;
  - (II) if the transaction involves a product or service that is not provided pursuant to a tariff, the value of the transaction shall be the higher of the utility's fully distributed cost or market price. Market price shall be either the price charged by the utility, or if this condition cannot be met, the lowest price charged by another person for a comparable product or service; or
  - (III) if the transaction involves the sale of an asset, the value of the transaction shall be the higher of net-book cost or market price. If the transaction involves the use of an asset, the value of the transaction shall be the higher of fully distributed cost or market price. Market price shall be either the price charged by the utility or if this condition cannot be met, the lowest price charged by another person in the market for the sale or use of a comparable asset, when such prices are publicly available.
- (e) For cost assignment and allocation purposes, the value of all transactions from a non-regulated activity to the utility shall be determined as follows:
- (I) if the transaction involves a product or service that is not provided pursuant to a tariff, the value of the transaction shall be the lower of the fully distributed cost or the market price except if the transaction results from a competitive solicitation process then the value of the transaction shall be the winning bid price. Fully distributed cost in this circumstance, shall be the cost that would be incurred by the utility to provide the service internally. Market price shall be either the price charged by the supplying non-regulated activity or if that condition is not met, the lowest price charged by other persons in the market for a comparable product or service, when such prices are publicly available; or
  - (II) if the transaction involves the sale of an asset, the value of the transaction shall be the lower of net-book cost or market price. If the transaction involves the use of an asset, the value of the transaction shall be at the lower of fully distributed cost or market price. Market price shall be either the price charged by the non-regulated activity or, if this condition cannot be met, the lowest price charged by another person in the market for the sale or use of a comparable asset, where such prices are publicly available.
- (f) If it is impracticable for the utility to establish a market price pursuant to paragraphs (d) or (e), the utility shall provide a statement to that effect, including its reasons in its' fully distributed cost study as well as its proposed method and amount for valuing the transaction. Parties in a Commission proceeding retain the right to advocate alternative market prices pursuant to paragraphs (d) and (e).

- (g) A utility may classify non-jurisdictional services as regulated if the services are rate-regulated by another agency (i.e., another state utility commission or the FERC) and where there are agency-accepted principles or methods for the development of rates associated with such services. This rule may apply, for example, to a provider's wholesale sales of electric power and energy. For such services, the utility shall identify the services in its manual, and account for the revenues, expenses, assets, liabilities, and rate base associated with these services as if these services are regulated.
- (h) For cost assignment and allocation purposes, the value of all transactions between regulated divisions within a utility shall be determined as follows:
  - (I) if the transaction involves a service provided by the utility pursuant to tariff, the value of the transaction shall be at the tariff rate, or
  - (II) if the transaction involves a service or function that is not provided pursuant to a tariff, the value of the transaction shall be at cost.
- (i) If the utility offers a service that is a combination of regulated and non-regulated activities (i.e., a bundled service), the utility shall assign and/or allocate costs to the regulated and non-regulated activities separately.
- (j) A utility may classify incidental activities as regulated activities. If an incidental activity is classified as a regulated activity, the utility shall clearly identify the activity as an incidental activity, and account for the revenues, expenses, assets, liabilities and rate base items as if that activity were a regulated activity.
- (k) To the extent possible, all assigned and allocated costs between regulated and non-regulated activities should have an audit trail which is traceable on the books and records of the applicable regulated utility to the applicable accounts pursuant to the Federal Energy Regulatory Commission Uniform System of Accounts.
- (l) In a rate proceeding involving the calculation of revenue requirements, a complaint proceeding where cost assignments or allocations are at issue, or a proceeding where CAAM approval is sought, the utility or any party may advocate a cost allocation principle other than that already in use, if the Commission has already approved the principle for that cost. The party requesting the alternative approach shall have the burden of proving the need for an alternative principle and why the particular principle is appropriate for the particular cost.

**4503. Cost Assignment and Allocation Manuals.**

- (a) Each utility shall maintain on file with the Commission an approved indexed cost assignment and allocation manual which describes and explains the calculation methods the utility uses to segregate and account for revenues, expenses, assets, liabilities, and rate base cost components assigned or allocated to Colorado jurisdictional activities. It includes the calculation methods to segregate and account for costs between and among jurisdictions, between regulated and non-regulated activities, and between and among utility divisions.
- (b) Each utility shall include the following information in its CAAM.

- (I) A listing of all regulated or non-regulated divisions of the Colorado utility together with an identification of the regulated or non-regulated activities conducted by each.
  - (II) A listing of all regulated or non-regulated affiliates of the Colorado utility together with an identification of which affiliates allocate or assign costs to and from the Colorado utility.
  - (III) A listing and description of each regulated and non-regulated activity offered by the Colorado utility. The Colorado utility shall provide a description in sufficient detail to identify the types of costs associated with the activity and shall identify how the activity is offered to the public and identify whether the Colorado utility provides the activity in more than one state. If an activity is offered subject to tariff, the Colorado utility may identify the tariff and the tariff section that describes the service offering in lieu of providing a service description.
  - (IV) A listing of the revenues, expenses, assets, liabilities and rate base items by Uniform System of Accounts account number that the utility proposes to include in its revenue requirement for Colorado jurisdictional activities including those items that are partially allocated to Colorado as well as those items that are exclusively assigned to Colorado.
  - (V) A detailed description showing how the revenues, expenses, assets, liabilities and rate base items by account and sub-account are assigned and/or allocated to the Colorado utility's non-regulated activities, along with a description of the methods used to perform the assignment and allocations.
  - (VI) A description of each transaction between the Colorado utility and a non-regulated activity which occurred since the Colorado utility's prior CAAM was filed and, for each transaction, a statement as to whether, for this Commission's jurisdictional cost assignment and allocation purposes, the value of the transactions is at cost or market as applicable.
  - (VII) A description of the basis for how the assignment or allocation is made.
  - (VIII) If the utility believes that specific cost assignments or allocations are under the jurisdiction of another authority, the utility shall so state in its CAAM and give a written description of the prescribed methods. Nothing herein shall be construed to be a delegation of this Commission's ratemaking authority related to those assignments or allocations.
  - (IX) Any additional information specifically required by Commission order.
- (c) A utility may treat certain transactions as confidential pursuant to the Commission rules on confidentiality.
  - (d) Following the initial approval of its CAAM, the utility shall file an updated CAAM in each rate case proceeding where revenue requirements are determined or every five years following approval of the CAAM then in effect, whichever is earlier.
  - (e) The utility may, at its discretion, file an application seeking Commission approval of updates to its CAAM at any time.

- (f) Whenever a utility files for approval of an update to its CAAM as a result of paragraph (d) or (e) above, the utility shall also simultaneously file a FDC study reflecting the results of the cost allocation methods in its updated manual.
- (g) Each utility shall maintain all records and supporting documentation concerning its CAAMs for so long as such manual is in effect or are subject to a complaint or any active proceeding involving cost allocation before the Commission for as long as such proceeding may be open.

**4504. Fully Distributed Cost Study.**

- (a) The utility shall submit its fully distributed cost study in both electronic and paper format simultaneously with filing its CAAM for all Colorado divisions and activities.
- (b) The utility shall prepare a FDC study that identifies all the non-regulated activities provided by each division in Colorado. The FDC study shall show the revenues, expenses assets, liabilities and rate base items assigned and allocated to each non-regulated activity. If the utility has more than one division (e.g., gas, electric, thermal or non-utility) in Colorado, the FDC study shall include a summary of all assigned and allocated costs by division.
- (c) In preparation of its FDC study, the utility shall complete an analysis of each non-regulated activity to identify the costs that are associated with and/or should be charged to each non-regulated activity to ensure each non-regulated activity is assigned and allocated the appropriate amount of revenues, expenses, assets, liabilities and rate base items.
- (d) If the CAAM is filed in connection with a rate case, the FDC study shall be based on the same test year used in the utility's rate case filing. The utility's FDC study shall include revenues, expenses, assets, liabilities and rate base items in order for the Commission to determine if all appropriate revenues, expenses, assets, liabilities and rate base items have been appropriately assigned and allocated, and to determine the utility's compliance with the principles established in rule 4502. For each assignment and allocation the utility shall:
  - (I) identify the revenues, expenses, assets, liabilities and rate base items by account number, sub-account number and account description; and
  - (II) for each account in (I) above, identify the assignment and allocation method used to assign and allocate costs in sufficient detail to verify the assignment and allocation method used to assign and allocate costs to Colorado divisions and activities is accurate and consistent with the utility's CAAM methodology and reference the CAAM section that describes the allocation; and
  - (III) provide the test year dollar itemized amounts of revenues, expenses, assets, liabilities, and rate base assigned and allocated to each Colorado division and non-regulated activity; the itemized amounts assigned and allocated to the Colorado utility for regulated activities; the itemized amounts assigned and allocated to the Colorado utility for Colorado non-regulated activities; and the itemized amounts assigned and allocated to other jurisdictions.



- (e) Each utility shall maintain all records and supporting documentation concerning its FDC study for so long as such study is in effect or are subject to a complaint or a proceeding before the Commission.

**4505. Disclosure of Non-regulated Goods and Services.**

Whenever a Colorado utility engages in the provision or marketing of non-regulated goods or services in Colorado that are not subject to Commission regulation, and the Colorado utility's name or logo is used in connection with the provision of such non-regulated goods and services in Colorado, there must be conspicuous, clear, and concise disclosure to prospective customers that such non-regulated goods and services are not regulated by the Commission. Such disclosure to prospective customers in Colorado shall be included in all Colorado advertising or marketing materials, proposals, contracts, and bills for non-regulated goods and services, regardless of whether the Colorado utility provides such non-regulated goods or services in Colorado directly or through a division or affiliate.

**4506. – 4599. [Reserved].**

**GAS COST ADJUSTMENT AND PRUDENCE REVIEW**

**4600. Overview and Purpose.**

Rules 4601 through 4609 are used by LDCs to revise gas rates on an expedited basis. These rules provide instructions for the filing of: gas cost adjustment applications; annual gas purchase plan submittals; and annual gas purchase reports. The purpose of the Gas Cost Adjustment is to enable LDCs, on an expedited basis, to reflect in their rates for gas sales and gas transportation services, as applicable, the increases or decreases in gas costs, including (but not limited to) gas commodity costs and upstream services costs. The purpose of the Gas Purchase Plan is to describe the LDC's plan for purchases of gas commodity and upstream services in order to meet the forecasted demand for sales gas service during each month of the gas purchase year. The purpose of the Gas Purchase Report is to present the LDC's actual purchases of gas commodity and upstream services during each month of the gas purchase year.

**4601. Definitions.**

The following definitions apply to rules 4600 through 4609 unless a specific statute or rule provides otherwise. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- (a) "Account No. 191" means an account under the Federal Energy Regulatory Commission System of Accounts used to accumulate actual under-or-over recovered gas supply costs.
- (b) "Base gas cost" means a rate component which is expressed in at least the accuracy of one mil (\$0.001) per Mcf or Dth which reflects the cost of gas commodity and upstream services, when applicable, included in the utility's base rates for sales gas and gas transportation service.
- (c) "Base rates" means the utility's currently-effective rates for sales gas and gas transportation service as authorized by the Commission in the utility's last general rate case.

- (d) "Current gas cost" means a rate component of the GCA which is expressed in at least the accuracy of one mil (\$0.001) per Mcf or Dth and which reflects the cost of gas commodity and upstream service projected to be incurred by the utility during the GCA effective period.
- (e) "Deferred gas cost" means a rate component of the GCA which is expressed in at least the accuracy of one mil (\$0.001) per Mcf or Dth and which is designed to amortize over the GCA effective period the under- or over-recovered gas costs reflected in the utility's Account No. 191 or other appropriate costs for a defined period such as a gas purchase year.
- (f) "Forecasted design peak day quantity" means the total quantity of gas commodity anticipated to be required to meet firm sales and firm gas transportation service demand on the utility's system on a design or historical peak day.
- (g) "Forecasted gas commodity cost" means the cost of gas commodity, including appropriate adjustments for storage gas injections and withdrawals and for exchange gas imbalances, which is projected to be incurred by the utility during the GCA effective period and which is determined by using forecasted gas purchase quantity and forecasted purchase prices.
- (h) "Forecasted gas purchase quantity" means the quantity of gas commodity the utility anticipates it will purchase during the GCA effective period, based upon the forecasted sales gas quantity, adjusted for system gas loss, use, or other anticipated variances.
- (i) "Forecasted purchase prices" means index prices, fixed prices, or other gas contracting price options used in the calculation of the forecasted gas commodity cost.
- (j) "Forecasted sales gas quantity" means the quantity of gas commodity projected to be sold by the utility during the GCA effective period, based upon the normalized quantity of gas commodity sales, adjusted for anticipated changes.
- (k) "Forecasted upstream service cost" means the total cost of upstream services projected to be incurred by the utility during the GCA effective period.
- (l) "Gas commodity throughput" means the amount of gas commodity flowing through the utility's jurisdictional gas facilities during a defined period of time.
- (m) "Gas cost adjustment" or "GCA" means the tariff mechanism by which a gas rate is adjusted to reflect increases or decreases in gas costs.
- (n) "GCA effective period" means the period of time that the GCA rate change is intended to be in effect before being superseded on the effective date of the next scheduled GCA.
- (o) "Gas purchase plan" (GPP) means a submittal pursuant to rule 4605 that describes the utility's planned purchases of gas commodity and upstream services to be used to meet sales gas demand during the gas purchase year.
- (p) "Gas purchase report" (GPR) means a report pursuant to rule 4607 which is filed with the Commission and which describes the utility's actual purchases of gas commodity and upstream services in order to meet sales gas demand during the gas purchase year.

- (q) "Gas purchase year" means a 12-month period from July 1 through June 30.
- (r) "Gas transportation service" means the delivery of gas commodity on the utility's pipeline system (either transmission or distribution) pursuant to any of the utility's gas transportation rate schedules on file with the Commission.
- (s) "Index price" means a published figure identifying a representative price of natural gas commodity available in a geographic area or at specific gas purchasing points during a specified time interval (i.e., daily, weekly, or monthly).
- (t) "Mil" means one-tenth of one cent (\$0.001).
- (u) "Normalized" means the process of adjusting gas quantities to reflect normal historic temperature based on National Oceanic and Atmospheric Administration data or other data as appropriate.
- (v) "Peak day" means a defined period (such as a 24 hour period or a three consecutive coincidental or non-coincidental day average), not less than 24 hours, during which gas commodity throughput is at its maximum level on the utility's system.
- (w) "Receipt point/area" means the point or group of points in a discrete geographic area, such as a supply basin, hub, or market area, at which the utility acquires title to the gas commodity purchased.
- (x) "Sales gas service" means the regulated sale of gas commodity by the utility to customers on the utility's jurisdictional gas system.
- (y) "Service level" means the type or level (whether base, swing, or peak) of gas supply service contracted for by the utility based upon the respective obligations of the supplier to deliver and sell, and the utility to take and purchase, gas commodity.
- (z) "Upstream services" means all transmission, gathering, compression, balancing, treating, processing, storage, and like services performed by others under contract with the utility for the purpose of effectuating delivery of gas commodity to the utility's jurisdictional gas facilities.

**4602. Schedule for Filings by Utilities.**

Utilities subject to rules 4600 through 4609 shall make the required filings in accordance with the following schedule:

- (a) October 1 filing schedule. Public Service Company of Colorado, and Atmos Energy Corporation, shall file with the Commission annual GCA applications with an effective date of October 1. Additional GCA applications may also be filed as necessary pursuant to paragraph 4603(c). The GPR for the preceding gas purchase year in which a GPP was filed shall be filed as a separate filing at the same time as the annual GCA application to be effective October 1.
- (b) November 1 filing schedule. Black Hills/Colorado Gas Utility Company, LP; Black Hills Gas Distribution, LLC; Durango Mountain Utilities; and Colorado Natural Gas, Inc. shall file with the Commission annual GCA applications with an effective date of November 1. Additional GCA applications may also be filed as necessary pursuant to paragraph 4603(c). The GPR for the

preceding gas purchase year in which a GPP was filed shall be filed as a separate filing at the same time as the annual GCA application to be effective November 1.

- (c) All utilities shall file their GPP submittal annually on or before June 1 for the next gas purchase year beginning July 1.

**4603. Gas Cost Adjustments.**

- (a) A utility shall file an application to adjust its GCA. The GCA application shall be filed pursuant to the schedule provided in rule 4602. A utility shall file a GCA application not less than two weeks in advance of the proposed effective date.
- (b) A GCA application shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) the information required by paragraphs 4002(b) and 4002(c); and
  - (II) the information required by rule 4604. Attachments 2, 3, 5 and 6 listed in rule 4604 shall be provided in written form and shall be provided electronically, in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by the Commission staff.
- (c) If the projected gas costs have changed from those used to calculate the currently effective gas cost or if a utility's deferred gas cost balance increases or decreases sufficiently, the utility may file an application to revise its currently effective GCA to reflect such changes, provided that the resulting change to the GCA equates to at least one cent (\$0.01) per Mcf or Dth.
- (d) Applicability of the GCA. The GCA shall be applied to all utility sales gas rate schedules. A utility engaged in the provision of gas transportation service may calculate a GCA that may be applied to transportation gas rate schedules in order to reflect appropriate costs. Absent a Commission decision, a utility engaged in the provision of gas transportation service shall not be required to calculate a transportation GCA factor.
- (e) Interest on under- or over-recovery. The amount of net interest accrued on the average monthly balance in Account No. 191 (whether positive or negative), is determined by multiplying the monthly balance by an interest rate equal to the Commission-authorized customer deposit rate for gas utilities. If net interest is positive, it will be excluded from the calculation of the deferred gas cost.
- (f) Price volatility risk management costs (hedging). Costs related to gas price volatility risk management for jurisdictional gas supply may be included for recovery through the GCA, if allowed by tariffs or by Commission decision. Such costs are subject to the prudence review and standard provided in rule 4607.
- (g) Calculation of the GCA. The GCA shall be calculated to at least the accuracy of one mil per Mcf or Dth pursuant to the following formula, subject to individual GCA rule variances granted by the Commission:

$$\text{GCA} = (\text{current gas cost} + \text{deferred gas cost}) - (\text{base gas cost}).$$

**4604. Contents of GCA Applications.**

- (a) A GCA application shall meet the following requirements.
  - (I) Every application shall contain attachments 1 through 9. Attachments 10 through 12 shall be filed with the annual GCA application. The attachments shall meet the requirements set out in this rule.
  - (II) The attachments shall be organized in a manner that specifically references, and responds to, the requirements contained in each subparagraph of this rule.
  - (III) Cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment shall be submitted and provided to Commission staff at the same time as the application.
  - (IV) The application shall cross-reference the proceeding numbers of the associated GPP submittals.
  - (V) When preparing attachments 10 through 12, the rate base, net operating earnings, capital structure, and cost of capital shall be calculated in conformance with the regulatory principles authorized by the Commission in the utility's most recent general rate case, including all required pro forma adjustments.
  - (VI) An explanation of all pro forma adjustments shall be provided.
- (b) GCA attachment No. 1 - GCA Summary. This attachment shall clearly illustrate all of the following principles.
  - (I) The impact the utility's currently effective GCA has on each sales gas customer class and, when applicable, the gas transportation rate class on a total dollar and mil (\$0.001, minimum) per Mcf or Dth basis.
  - (II) The impact the utility's proposed GCA has on each sales gas customer class and, when applicable, gas transportation rate class on a total dollar and mil (\$0.001, minimum) per Mcf or Dth basis; and
  - (III) The percent change in total bill for a customer of average usage for each sales gas customer class. This percent change in total bill calculation shall include an itemization of the monthly service and facility charge, base rates and GCA commodity components, and all other tariff charges on the customer bill.
- (c) GCA attachment No. 2 - Current Gas Cost Calculation. This attachment shall contain the calculation of the current gas cost and shall provide month-by-month information with respect to the forecasted gas commodity cost, forecasted gas purchase quantity, forecasted market prices, forecasted upstream service cost, and forecasted sales gas quantity.
  - (I) The utility shall calculate current gas cost at least to the accuracy of the nearest mil (\$0.001) per Mcf or Dth according to the following formula, subject to individual GCA rule variances granted by the Commission:

current gas cost = (forecasted gas commodity cost + forecasted upstream service cost) / forecasted sales gas quantity.

- (II) The utility shall present all such information in a format comparable with, and corresponding to, the information forecasted in the utility's GPP submittal for each month of the GCA effective period, as required pursuant to rule 4606.
- (d) GCA attachment No. 3 - Deferred Gas Cost Calculation. This attachment shall contain the details of the utility's actual gas purchase costs and the calculation of deferred gas cost. In addition, this attachment shall provide month-by-month information detailing the activity in USOA Account No. 191 by subaccount and period as applicable, interest on under- or over-recovery, and all other included gas costs authorized for recovery in the GCA. The utility shall calculate deferred gas cost as the aggregate total of the under- or over-recovered gas costs reflected in its Account No. 191, or other approved gas costs, recorded at the close of business for each month of the period at issue (such as the previous gas purchase year), plus interest on under- or over-recovery (if net amount is negative), divided by forecasted sales gas quantity. The utility shall calculate deferred gas cost at least to the accuracy of the nearest mil per Mcf or Dth. Each cost a utility includes in the deferred gas cost calculation shall be itemized and clearly identified and itemized for applicability to the period at issue. In its annual GCA applications the utility shall reflect actual deferred costs for the most recent period ending June 30, or as otherwise approved by the Commission.
- (e) GCA attachment No. 4 - Current Tariff. This attachment shall contain the tariff pages which illustrate the gas cost components of the utility's currently-effective rates for sales gas service and, where applicable, gas transportation service.
- (f) GCA attachment No. 5 - Forecasted Gas Transportation Demand. This attachment applies only to utilities that have a GCA component within their authorized rates for gas transportation service. This attachment shall provide the following information, with all demand forecast information provided on a Mcf or Dth basis:
- (I) a forecast of gas commodity throughput attributable to gas transportation service for each month of the GCA effective period; and
  - (II) a forecast of firm backup supply demand quantities (to the extent the utility has such service) under the utility's firm gas transportation service agreements for each month of the GCA effective period.
- (g) GCA attachment No. 6 - current gas cost allocations. This attachment shall fully explain and justify the method(s) used to do each of the following:
- (I) allocate the costs associated with the gas commodity and upstream services to each specific sales gas customer class and, where applicable, gas transportation customer rate class; and
  - (II) derive the amount of the GCA applied to each specific sales gas customer class and, where applicable, gas transportation customer rate classes.

- (h) GCA attachment No. 7 - Customer Notice. This attachment shall provide the form of notice to customers and the public concerning the utility's proposed GCA change. In its customer notice for each sales gas customer class, the utility shall include the following:
  - (I) current and proposed GCA rates and percentage change;
  - (II) comparison of the previous gas purchase year's last average annual bill under prior rates and the projected average annual bill under the proposed GCA rates and percentage change in the total bill amount using an average usage amount for each customer class;
  - (III) comparison of the prior year's peak winter month bill under prior rates and the projected peak winter month bill under the proposed GCA rates and percentage change using an average peak winter month usage amount for each customer class; and
  - (IV) with the annual GCA application, a statement that the utility made a separate gas purchase report filing in accordance with rule 4607 to begin the initial prudence review evaluation process for the prior gas purchase year.
- (i) GCA attachment No. 8 - components of delivered gas cost. This attachment shall detail the itemized rate components of delivered gas cost to the customer (rate), per rule 4406.
- (j) GCA attachment No. 9 - proposed tariff. This attachment shall contain the tariff sheets proposed by the utility to reflect the proposed GCA change.
- (k) GCA attachment No. 10 - rate base. This attachment shall calculate the used and useful rate base assets employed by the utility for Commission-regulated gas operations for the most recently completed 12-month period ending June 30.
- (l) GCA attachment No. 11 - net operating earnings. This attachment shall calculate the utility's net operating earnings for jurisdictional gas operations during the most recently completed 12-month period ending June 30.
- (m) GCA attachment No. 12 - capital structure and cost of capital. This attachment shall calculate the following information for the most recently completed 12-month period ending June 30, the utility's:
  - (I) capital structure for jurisdictional gas operations;
  - (II) cost of long-term debt and preferred equity;
  - (III) cost of common equity; and
  - (IV) weighted average cost of capital.

**4605. Gas Purchase Plans.**

- (a) GPP filing requirements. The utility shall file its GPP as a "Submittal for Determination of Completeness of GPP." This submittal shall include the following proceeding caption: "In the

matter of Gas Purchase Plans and Gas Purchase Reports for [utility] for the Gas Purchase Year from July 1, [year] through June 30, [year]."

- (b) Contents of GPP filing. In the GPP, the utility shall submit to the Commission the following:
  - (I) the information required by rule 4606;
  - (II) the utility's forecasted quantity of gas to be purchased over the ensuing gas purchase year for each service level;
  - (III) the utility's forecasted pricing for each receipt point/area; and
  - (IV) the utility's portfolio management plan.
- (c) Commission procedures for processing filings. Upon receipt of a GPP submittal, the Commission shall assign a proceeding number and shall review the submittal solely for completeness (i.e., compliance with the information requirements of these rules). The Commission shall not: hold a hearing on the substance of the GPP, entertain interventions by interested parties, require the filing of testimony or permit discovery. The Commission shall not render a decision approving or disapproving the substantive information contained in the submittal.
- (d) Review timelines. Commission staff shall review the submittal and, within 15 calendar days of the filing, shall provide written notification to the utility of any deficiencies in the submittal. The utility shall file the requested information, or a written statement indicating that the utility believes the additional information is not required, within 15 calendar days after the date of the Commission staff notification. Upon receipt of final information or the written statement, Commission staff shall place the submittal on the agenda for consideration at the next available Commissioners' weekly meeting. If the Commission fails to mail its determination on completeness of the submittal within 15 calendar days of receipt of final information or the written statement, the submittal shall be deemed complete.
- (e) Utilities with multiple GCA rate areas. A utility with more than one approved GCA rate area in Colorado shall file a separate GPP for each GCA rate area. These GPPs may be filed in a single submittal.
- (f) GPP no longer reflects market conditions. A utility shall file a new GPP within 30 days of its determination that the currently effective GPP no longer substantively reflects active purchasing conditions or the utility's planned purchasing practices.

**4606. Contents of the GPP.**

A GPP submittal shall contain the following attachments. The utility shall organize attachments in a manner that specifically references, and responds to, the requirements of paragraphs (a) through (d) of this rule. With its submittal, the utility shall provide cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment.

- (a) GPP attachment No. 1 - gas purchase schedule. This attachment shall provide a forecast of the specific gas commodity supplies, segregated by receipt point/area, which the utility plans to



purchase in order to meet forecasted sales gas demand during each month of the applicable gas purchase year.

- (b) GPP attachment No. 2 – gas purchasing pricing description. For each specific receipt point/area, this attachment shall provide an estimate of applicable ranges of forecast index prices expected to be incurred, short-term fixed prices (one-year or other appropriate term), and other relevant pricing options, as applicable to the portfolio management plan described in GPP attachment 3.
- (c) GPP attachment No. 3 – portfolio management plan. This attachment shall provide a plan stating how the utility plans to manage its gas supply portfolio for the gas purchase year. This attachment shall also include a description and analysis of the options the utility considered, or will consider, and the steps the utility has taken, or will take, to reduce customers' risk of gas price volatility for the gas purchase year. To the extent a utility proposes to use gas price volatility risk management tools, this attachment shall include a description of the utility's policy for implementing such risk management tools, including a projection of such costs and the assumptions underlying all cost estimates.
- (d) GPP attachment No. 4 - forecasted upstream service costs. This attachment shall include the following information for each month of the applicable gas purchase year:
  - (I) An itemized list of all upstream services, by provider and service level or rate schedule, and associated costs, that the utility expects to purchase in the upcoming gas purchase year in order to meet sales gas and gas transportation demand .
  - (II) A comparison of forecasted design peak day delivery quantity with all sources of capacity available to the utility, including forecasted upstream services, forecasted gas commodity to be purchased directly into the utility's distribution system (i.e., city gate purchases) on a firm basis, and the utility's own gas storage facilities or purchased gas storage capacity.
  - (III) A comprehensive explanation of the utility's forecasted level of planned upstream service purchases.
  - (IV) Forecasted capacity release volumes and revenues for release of upstream capacity by the utility.

**4607. Gas Purchase Reports and Prudence Reviews.**

- (a) GPR filing requirements. The utility shall file a GPR under the previous year's GPP proceeding number (filed approximately 15 months previously) as a separate filing from, and at the same time as, the annual GCA application. Specific attachments or other information may be filed under seal; however, an explanation of the confidential nature of the attachments or information must be included in the GPR filing.
- (b) Prudence review process. Based on the initial evaluation of the GPR, the Commission may initiate a prudence review hearing. The Commission shall initiate this hearing by written order within 120 days of the filing of the GPR. The prudence review may result in tariff or rate changes that could affect different classifications of customers.

- (c) Prudence review standard. For purposes of GCA recovery, the standard of review to be used in assessing the utility's action (or lack of action) in a specific gas purchase year is: whether the action (or lack of action) of a utility was reasonable in light of the information known, or which should have been known, at the time of the action (or lack of action).
- (d) Burden of proof. If the Commission elects to hold a hearing, the utility shall have the burden of proof and the burden of going forward to establish the reasonableness of actual gas commodity and demand costs paid by the utility, actual costs incurred in volatility management, and actual upstream service costs of any nature incurred during the review period.
- (e) Utility testimony and attachments. If the Commission sets a hearing, the utility shall file its testimony supporting gas cost recovery for the gas purchase year at issue. The testimony shall be filed in question-and-answer format. The utility shall file its testimony not later than 45 days after the Commission sets the matter for hearing.

**4608. Contents of the GPR.**

A GPR shall contain the following attachments. The utility shall organize the attachments in a manner that specifically references, and responds to, paragraphs (a) through (d) of this rule. The utility shall also present all such information in a format comparable with, and corresponding to, the information forecasted in the utility's GPP submittal as required pursuant to rule 4606 and GCA application pursuant to rule 4604. The utility shall provide an explanation of, and justification for, any material deviations from its GPP. All underlying support documentation and work papers shall be made available. With its filing, the utility shall provide cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment.

- (a) GPR attachment No. 1 - actual gas commodity purchases. This attachment shall provide, in a format comparable to the information provided in GPP attachment 1, the quantities of, and actual invoice costs of, specific gas commodity supplies, segregated by receipt point/area that the utility purchased in order to meet actual sales gas and gas transportation demand during the peak day and for each month of the gas purchase year.
- (b) GPR attachment No. 2 - description of actual market prices. This attachment shall provide, in a format comparable to the information provided in GPP attachment 2, actual index prices, short-term fixed prices (one-year, or other appropriate term), and other relevant pricing options for each specific receipt point area, as applicable to the portfolio management plan described in GPP and GPR attachments 3.
- (c) GPR attachment No. 3 - actual portfolio purchases. This attachments shall provide, in a format comparable to the information provided in GPP exhibit 3, a comparison of the utility's portfolio management plan and the results actually achieved through the implementation of this plan (or modification thereto), in order to demonstrate, using the standard of review specified in paragraph 4607(c), the prudence of actual portfolio purchases. This attachment shall include a detailed itemization of gas price volatility risk management costs if applicable.
- (d) GPR attachment No. 4 - actual upstream service costs. This attachment shall provide, in a format comparable to the information provided in GPP attachment 4, the following information for each month of the gas purchase year:

- (I) an itemized list of the upstream services the utility actually purchased in order to meet sales gas and gas transportation demand;
- (II) an itemized listing of the specific costs the utility incurred to purchase upstream services;
- (III) actual peak day demand experienced by the utility during the gas purchase year; and
- (IV) an itemized list of capacity release volumes and revenues.

**4609. General Provisions.**

- (a) For each attachment filed by the utility as confidential under rules 4600 through 4609, the utility shall provide, at a minimum, a version of the attachment with publicly available information.
- (b) A utility shall monitor the net under- or over-recovery balance in USOA Account No. 191 on a monthly basis. On a quarterly basis, or as otherwise established individually for a utility, a utility shall file, within 30 days of the end of the quarter, a report to the Commission stating the USOA Account No. 191 balance calculation for each rate area. The reports shall include the USOA Account No. 191 balance information specified in GCA attachment 3 and shall be filed in one common proceeding, established by the Commission to receive USOA Account No. 191 balance filings from all utilities. If the utility identifies a significant net under- or over- recovery balance during the gas purchase year, the utility shall initiate appropriate action to mitigate the significant under- or over- recovery balance.

**4610. – 4699. [Reserved].**

**APPEALS OF LOCAL GOVERNMENT LAND USE DECISIONS**

**4700. Scope and Applicability.**

Rules 4700 through 4707 apply to all utilities or power authorities which seek to appeal a local government action concerning a major natural gas facility.

**4701. Definitions.**

The following definitions apply to rules 4700 through 4707, unless a specific statute or rule provides otherwise. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- (a) "Local government" means a county, a home rule or statutory city, a town, a territorial charter city, or a city and county.
- (b) "Local government action" means (1) any decision, in whole or in part, by a local government which has the effect or result of denying a permit or application of a utility that relates to the location, construction, or improvement of a major natural gas facility or (2) a decision imposing requirements or conditions upon such permit or application that will unreasonably impair the ability of the utility to provide safe, reliable, and economical service to the public.

- (c) "Local land use decision" means the decision of a local government within its jurisdiction to plan for and regulate the use of land.
- (d) "Major natural gas facility" is defined by § 29-20-108(3)(e), C.R.S., or by any other applicable statute.
- (e) "Power authority" means an authority created pursuant to § 29-1-204, C.R.S.

**4702. Precondition to Application.**

In order for a utility or power authority to appeal a local government action to the Commission pursuant to this rule and pursuant to § 29-20-108, C.R.S., one or more of the following conditions must be met:

- (a) the utility or power authority has applied for or has obtained a certificate of public convenience and necessity from the Commission pursuant to § 40-5-101, C.R.S., to construct the major natural gas facility that is the subject of the local government action;
- (b) a certificate of public convenience and necessity is not required for the utility or power authority to construct the major natural gas facility that is the subject of the local government action; and
- (c) the Commission has previously entered an order pursuant to § 40-4-102, C.R.S., that conflicts with the local government action.

**4703. Applications.**

- (a) To commence an appeal of a local government land use decision, a utility or power authority shall file with the Commission an application pursuant to this rule.
- (b) An application filed in accordance with §§ 29-20-108, C.R.S., and this rule shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) all of information required in paragraphs 4002(b) and 4002(c);
  - (II) a showing that one of the preconditions set out in rule 4702 has been met;
  - (III) identification of the major natural gas facility;
  - (IV) identification of the local government action and its impact on the major natural gas facility;
  - (V) a statement of the reasons the applying utility or power authority believes that the local government action would unreasonably impair its ability to provide safe, reliable, and economical service to the public;
  - (VI) the demonstrated need for the major natural gas facility or reference to the application made to the Commission with respect to the major natural gas facility and the resulting decision of the Commission regarding such facility;

- (VII) the extent to which the proposed facility is inconsistent with existing applicable local or regional land use ordinances, resolutions, or master or comprehensive plans;
- (VIII) whether the proposed facility would exacerbate a natural hazard;
- (IX) applicable utility engineering standards, including supply adequacy, system reliability, and public safety standards;
- (X) the relative merit, as determined through use of the normal system planning evaluation techniques of the utility or power authority, of any reasonably available and economically feasible alternatives proposed by the utility, the power authority, or the local government;
- (XI) the impact that the local government action would have on the customers of the utility or power authority who reside within and without the boundaries of the jurisdiction of the local government;
- (XII) the basis for the local government action. If available, the utility or power authority shall attach a copy of the local government action;
- (XIII) the impact the proposed facility would have on residents within the local government's jurisdiction including, in the case of a right-of-way in which facilities have been placed underground, whether those residents have already paid to place such facilities underground. If the residents have already paid to place facilities underground, the Commission will give strong consideration to that fact;
- (XIV) information concerning how the proposed major natural gas facility will affect the safety of residents within and without the boundaries of the jurisdiction of the local government; and
- (XV) an attestation that the utility or power authority will, upon filing the application with the Commission, simultaneously send the application to the local government body which took the local government action which is the subject of the appeal.

**4704. Public Hearing.**

In addition to the formal evidentiary hearing on the appeal, and pursuant to § 29-20-108(5)(b), C.R.S., the Commission shall take statements from the public concerning the appealed local government action at a public hearing held at a location specified by the local government.

**4705. Prehearing Conference, Parties, and Public Notice.**

- (a) In order to assist the parties in scheduling the public hearing, determining the scheduling of the evidentiary hearing, developing the list of persons to receive notice of these hearings, and addressing other pertinent issues, the Commission will hold a prehearing conference.
- (b) The Commission shall conduct a prehearing conference within 15 days after the application is deemed complete by the Commission.

- (c) The Commission shall join as an indispensable party the local government which took the contested local government action.
- (d) Ten days before the commencement of the prehearing conference, the local government shall submit to the parties and the Commission its preference for the location of the public hearing to be held in accordance with § 29-20-108(5)(b), C.R.S., and rule 4704.
- (e) The Commission will decide the date and time of the public hearing after receiving comments from the parties at the prehearing conference.
- (f) By the date of the prehearing conference, each party shall provide to the utility a list of individuals and groups to receive notice of the public hearing.
- (g) The utility or power authority shall give notice of the public hearing to the identified individuals and groups in a manner specified by the Commission. Notice may be accomplished by newspaper publication, bill insert, first class mail, or any other manner deemed appropriate by the Commission.
- (h) If the local government is unable to provide meeting space for the public hearing, and space needs to be acquired, then the utility or power authority shall bear any cost associated with the rental of such space for the public hearing.
- (i) The parties are encouraged to confer prior to the prehearing conference to develop a schedule for the filing of testimony and the dates for the formal evidentiary hearing.

**4706. Denial of Appeal.**

In accordance with § 29-20-108(5)(e), C.R.S., the Commission shall deny an appeal of a local government action if the utility or power authority has failed to comply with the following notification and consultation requirements:

- (a) A utility or power authority shall notify the affected local government of its plans to site a major natural gas facility within the jurisdiction of the local government prior to submitting the preliminary or final permit application, but in no event later than filing a request for a certificate of public convenience and necessity pursuant to Article 5 of Title 40, C.R.S., or the filing of any annual filing with the Commission that proposes or recognizes the need for construction of a new major natural gas facility or the extension of an existing facility. If a utility or power authority is not required to obtain a certificate of public convenience and necessity pursuant to Article 5 of Title 40, C.R.S., or to file annually with the Commission to notify the Commission of proposed construction of a new major natural gas facility or the extension of an existing facility, then the utility or power authority shall notify any affected local governments of its intention to site a new major natural gas facility within the jurisdiction of the local government when such utility or power authority determines that it intends to proceed to permit and to construct the facility. Following such notification, the utility or power authority shall consult with the affected local governments in order to identify the specific routes or geographic locations under consideration for the site of the major natural gas facility and to attempt to resolve land use issues that may arise from the contemplated permit application.

- (b) In addition to its preferred alternative within its permit application, the utility or power authority shall consider and present reasonable siting and design alternatives to the local government or shall explain why no reasonable alternatives are available.

**4707. Procedural Rules.**

Pursuant to § 29-20-108(5)(b), C.R.S., any appeal brought by a utility or power authority under this section shall be conducted in accordance with the procedural requirements of Article 6, Title 40, C.R.S., including § 40-6-109.5, C.R.S. Evidentiary hearings on any such appeals shall be conducted in accordance with § 40-6-109, C.R.S.

**4708. – 4749. [Reserved].**

**DEMAND SIDE MANAGEMENT**

**4750. Overview and Purpose.**

These rules implement §§ 40-1-102, 40-3.2-101, 40-3.2-103, and 40-3.2-105, C.R.S. for LDCs required by statute to be rate-regulated. Consistent with statutory requirements, the purpose of these Demand Side Management (DSM) rules is to reduce end-use natural gas consumption in a cost effective manner, in order to save money for consumers and utilities, and protect the environment by encouraging the reduction of emissions and air pollutants. These rules direct natural gas utilities in the design and implementation of programs that will enable sales customers to participate in DSM. The LDC shall design DSM programs for its full service customers to achieve cost-effective energy savings, considering factors such as: achievable energy savings, customer benefits, cost effectiveness ratios, adoption potential, market transformation capability and ability to replicate in the utility service territory.

- (a) Each utility shall file an application for approval of a DSM plan within the parameters set forth in these rules. In the application, the utility shall include a proposed expenditure target, savings target, funding mechanism, and cost-recovery mechanism.
- (b) Each utility shall annually file an advice letter or application for cost recovery, as permitted herein.
- (c) Each utility shall annually file a DSM report. The DSM report shall include the results of any measurement and verification (M&V) evaluation conducted during the DSM report period.

**4751. Definitions.**

The following definitions apply to rules 4750 through 4760, unless § 40-1-102 provides otherwise.

- (a) “Amortization” means the systematic spreading of expenditures or capital costs incurred for DSM programs, through regular accounting entries over a specified period of time.
- (b) “Benefit/cost ratio” means the ratio of the net present value of benefits to the net present value of costs, as calculated using the modified TRC test.
- (c) “Cost effective” means a benefit/cost ratio of greater than one.

- (d) “Demand side management” (DSM) means the implementation of programs or measures which serve to shift or reduce the consumption of, or demand for, natural gas.
- (e) “Discount rate” means the interest rate used in determining the present value of future cash flows of DSM costs and benefits, for both forecasted and actual cash flows. The forecasted DSM costs and benefits are used to estimate the cost effectiveness of DSM measures to develop a cost effective DSM portfolio. The actual DSM costs and benefits, which are the actual costs of the program and the documented energy savings, are used to determine net economic benefits for the purpose of calculating the bonus. Discount rate shall be the utility’s after-tax weighted average cost of capital (WACC).
- (f) “DSM education” means a program, including but not limited to an energy audit, that contributes indirectly to a cost-effective DSM program by promoting customer awareness and participation.
- (g) “DSM measure” means an individual component or technology, such as attic insulation or replacement of equipment.
- (h) “DSM period” means the effective period of an approved DSM plan.
- (i) “DSM plan” means the DSM programs, goals, and budgets over a specified DSM period, generally considered in one year increments, as may be proposed by the utility.
- (j) “DSM program” means any combination of DSM measures, information and services offered to customers to reduce natural gas usage.
- (k) “Energy efficiency program” see DSM program.
- (l) “Gas Demand-Side Management Cost Adjustment” (G-DSMCA) means a rate adjustment mechanism designed to compensate a utility for its DSM program costs.
- (m) “Gas Demand-Side Management bonus” (G-DSM bonus) means a bonus awarded to a utility in accordance with § 40-3.2-103(2)(d), C.R.S.
- (n) “Market transformation” means a strategy for influencing the adoption by consumers of new techniques or technologies. The objective is to overcome barriers within a market through coordinating tactics such as education, training, product demonstration and marketing, often conducted in concert with rebates or other financial incentives.
- (o) “Modified Total Resource Cost test” or “modified TRC test” means an economic cost-effectiveness test used to compare the net present value of the benefits of a DSM program or measure over its useful life, to the net present value of costs of a DSM measure or program for the participant and the utility, consistent with § 40-1-102(5), C.R.S. In performing the modified TRC test, the benefits shall include, but are not limited to, as applicable: the utility’s avoided production, distribution and energy costs; the participant’s avoided operating and maintenance costs; the valuation of avoided emissions; and non-energy benefits as set forth in rule 4753. Costs shall include utility and participant costs. The utility costs shall include the net present value of costs incurred in accordance with the budget set forth in rule 4753.



- (p) “Net economic benefits” means the net present value of all benefits in the modified TRC test, as applied to the utility’s portfolio of DSM programs, less the net present value of the costs in the modified TRC test associated with that same portfolio.
- (q) “Sales customer” or “full service customer” means a residential or commercial customer that purchases a bundled natural gas supply and delivery service from a utility but does not include customers served under a utility’s gas transportation service rate schedules.

**4752. Filing Schedule.**

- (a) Each utility shall implement and maintain its DSM plan and G-DSMCA, as approved by the Commission.
- (b) Each utility shall submit its annual DSM report on or before April 1 of each year.
- (c) Each utility seeking a G-DSM bonus shall file an application pursuant to rule 4760 requesting approval of such bonus on or before April 1 of each year.
- (d) Each utility shall file an advice letter on or before May 31 of each year to adjust the G-DSMCA to be effective July 1 for a period of 12 months. Alternatively, each utility may file a combined application on or before April 1 of each year seeking a G-DSM bonus, as well as an adjustment to the G-DSMCA, to be effective July 1 for a period of 12 months.
- (e) By May 1 of the final year of the currently effective DSM plan, each utility shall file by application a prospective natural gas DSM plan for Commission approval.

**4753. Periodic DSM Plan Filing.**

Each utility shall periodically file, in accordance with paragraph 4752(e), a prospective natural gas DSM plan that covers a DSM period of three years, unless otherwise ordered by the Commission. The plan shall include the following information:

- (a) the utility’s proposed expenditures by year for each DSM program, by budget category; the sum of these expenditures represents the utility’s proposed expenditure target as required by § 40-3.2-103(2)(a), C.R.S.;
- (b) the utility’s estimated natural gas energy savings over the lifetimes of the measures implemented in a given annual DSM program period, expressed in dekatherms per dollar of expenditure, and presented for each DSM program proposed for Commission approval; this represents the utility’s proposed savings target required by § 40-3.2-103(2)(b), C.R.S.;
- (c) the anticipated units of energy to be saved annually by a given annual DSM program, which equals the product of the proposed expenditure target and proposed savings target; this product is referred to herein as the energy target;
- (d) the estimated dollar per therm value that represents the utility’s annual fixed costs that are recovered through commodity sales on a per therm basis;

- (e) the utility shall include in its DSM plan application data and information sufficient to describe the design, implementation, oversight and cost effectiveness of the DSM programs. Such data and information shall include, at a minimum, program budgets delineated by year, estimated participation rates and program savings (in therms);
- (f) in the information and data provided in a proposed DSM plan, the utility shall reflect consideration of the factors set forth in the Overview and Purpose, rule 4750. At a minimum the utility shall provide the following information detailing how it developed its proposed DSM program:
  - (I) descriptions of identifiable market segments, with respect to gas usage and unique characteristics;
  - (II) a comprehensive list of DSM measures that the utility is proposing for inclusion in its DSM plan;
  - (III) a detailed analysis of proposed DSM programs for a utility's service territory in terms of markets, customer classes, anticipated participation rates (as a number and a percent of the market), estimated energy savings and cost effectiveness;
  - (IV) a ranking of proposed DSM programs, from greatest value and potential to least, based upon the data required in subparagraph (f)(III);
  - (V) proposed marketing strategies to promote participation based on industry best practices;
  - (VI) calculation of cost effectiveness of the proposed DSM programs using a modified TRC test. Each proposed DSM program is to have a projected value greater than or equal to 1.0 using a modified TRC test, except as provided for in paragraph 4753 (g);and
  - (VII) an analysis of the impact of the proposed DSM program expenditures on utility rates, assuming a 12-month cost recovery period.
- (g) In its DSM plan, the utility shall address how it proposes to target DSM services to low-income customers. The utility shall also address whether it proposes to provide DSM services directly or indirectly through financial support of conservation programs for low-income households administered by the State of Colorado, as authorized by § 40-3.2-103(3)(a), C.R.S. The utility may propose one or more low-income DSM programs that yield a modified TRC test value below 1.0.
- (h) In proposing an expenditure target for Commission approval, pursuant to § 40-3.2-103 (2)(a), C.R.S., the utility shall comply with the following:
  - (I) the utility's annual expenditure target for DSM programs shall be, at a minimum, two percent of a natural gas utility's base rate revenues, (exclusive of commodity costs), from its sales customers in the 12-month calendar period prior to setting the targets, or one-half of one percent of total revenues from its sales customers in the 12-month calendar period prior to setting the targets, whichever is greater;
  - (II) the utility may propose an expenditure target in excess of two percent of base rate revenues; and

- (III) funds spent for education programs, market transformation programs and impact and process evaluations and program planning related to natural gas DSM programs may be recovered without having to show that such expenditures, on an independent basis, are cost-effective; such costs shall be included in the overall benefit/cost ratio analysis.
- (i) The utility shall propose a budget to achieve the expenditure target proposed in paragraph 4753 (a). The budget shall be detailed for the overall DSM plan and for each program for each year and shall be categorized into:
  - (I) planning and design costs;
  - (II) administrative and DSM program delivery costs;
  - (III) advertising and promotional costs, including DSM education;
  - (IV) customer incentive costs;
  - (V) equipment and installation costs;
  - (VI) measurement and verification costs; and
  - (VII) miscellaneous costs.
- (j) The budget shall explain anticipated increases/decreases in financial resources and human resources from year to year.
- (k) A utility may spend more than the annual expenditure target established by the Commission up to 25 percent over the target, without being required to submit a proposed DSM plan amendment. A utility may submit a proposed DSM plan amendment for approval when expenditures are in excess of 25 percent over the expenditure target.
- (l) As a part of its DSM plan, each utility shall propose a DSM plan with a benefit/cost value of unity (1) or greater, using a modified TRC test.
- (m) For the purposes of calculating a modified TRC, the non-energy benefits of avoided emissions and societal impacts shall be incorporated as follows.
  - (I) The initial TRC ratio, which excludes consideration of avoided emissions and other societal benefits, shall be multiplied by 1.05 to reflect the value of the avoided emissions and other societal benefits. The result shall be the modified TRC. A utility may propose for approval a different factor for avoided emissions and societal impacts, but must submit documentation substantiating the proposed value.
- (n) Measurement and verification (M & V) plan. The utility shall describe in complete detail how it proposes to monitor and evaluate the implementation of its proposed programs. The utility shall explain how it will accumulate and validate the information needed to measure the plan's performance against the standards, pursuant to rule 4755. The utility shall propose measurement and verification reporting sufficient to communicate results to the commission in a detailed, accurate and timely basis.

**4754. Annual DSM Report and Application for Bonus and Bonus Calculation.**

On the schedule set forth in rule 4752, the utility shall provide the Commission a detailed DSM report and application for bonus.

- (a) In the annual DSM report, the utility shall describe its actual DSM programs as implemented. For each DSM program, the utility shall document actual program expenditures, energy savings, participation levels and cost-effectiveness.
- (b) Annual program expenditures shall be separated into cost categories contained in the approved DSM plan.
- (c) For each DSM program, the utility shall compare the program's proposed and actual expenditures, savings, participation rate, and cost-effectiveness; in addition, the utility shall prepare an assessment of the success of the program, and list any suggestions for improvement and greater customer involvement.
- (d) The utility shall provide actual benefit/cost results for the overall DSM plan and individual DSM programs implemented during the plan year. The benefit/cost analysis shall be based on the costs incurred and benefits achieved, as identified in the modified TRC test. Benefit values are to be based upon the results of M & V evaluation, when such has been conducted as set forth in rule 4755. Otherwise, the benefit values of the currently approved DSM plan are to be used.
- (e) If the annual report covers a year within which an M & V evaluation was completed, the complete M & V results are to be included as part of the annual report.
- (f) The utility may file an application for bonus, pursuant to rule 4760. The application for bonus shall include the utility's calculation of estimated bonus applying the methodology set forth in this rule to the utility's actual performance.
- (g) The Commission shall determine the level of bonus, if any, that the utility is eligible to collect on the basis of the information included in the report, pursuant to the bonus criteria and process set forth, below.
  - (l) The primary objective of the bonus is to encourage cost-effective energy savings. The amount of bonus earned, if any, will correlate with the utility's performance relative to the approved savings target (dekatherms saved per dollar expended) and the energy target. Assuming all other factors that affect consumption remain unchanged, effective DSM programs will reduce per customer commodity consumption, which may lead to revenue reductions for the utility. The utility may include in the bonus application a request for approval to recover a calculated amount of revenue that acknowledges the DSM program reduced the utility's revenue. The recovery amount for reduced revenue is separate from any bonus determined by the Commission and shall be calculated, as follows:
    - (A) the utility shall calculate a dollar per therm value that represents the utility's annualized fixed costs that are recovered through commodity sales on a per therm basis;

- (B) the utility shall include in the DSM filing pursuant to rule 4753 a proposed dollar per therm value with the calculation methodology and supporting documentation;
  - (C) the recovery amount for reduced revenue shall be calculated by multiplying the dollar per therm value by the annualized number of therms saved and reported in the utility's annual DSM report for the plan year;
  - (D) the recovery of the reduced revenue amount shall be through the Demand-Side Management Cost Adjustment (DSMCA), over the same twelve month period in which any approved bonus amount is recovered, as set forth in subparagraph 4752 (b)(l); and
  - (E) for the purpose of inclusion in the above calculation, the annual report shall include the number of therms projected to be saved from the DSM programs in the twelve months following the end of the program year.
- (II) As a threshold matter, the utility must expend at least the minimum amount set forth in subparagraph 4753 (h)(l), in order to earn a bonus.
- (III) The bonus amount is a percentage of the net economic benefits resulting from the DSM plan over the period under review. The percentage value is the product of the two factors:
- (A) The Energy Factor is determined by the percentage of the energy target achieved by the utility. The energy factor is zero plus 0.5 percent for each one percent above 80 percent of the energy target achieved by the utility.
  - (B) The Savings Factor is the actual savings achieved divided by the approved savings target. The actual savings achieved and approved savings target are each expressed in dekatherms saved per dollar expended.
- (IV) The following is provided as an example of the bonus calculation, using these illustrative numbers: utility achieves 106 percent of its energy target; the utility's savings target is 15,000 dekatherms per \$1 million expended, and the utility's actual savings is 18,000 dekatherms per \$1 million.
- The energy factor would be:  $50 \text{ percent} \times (106 - 80)$ , or 13 percent
- The savings factor would be:  $18,000/15,000$  or 1.2
- The resulting bonus percentage would be:  $13 \text{ percent} \times 1.2$ , or 15.6 percent. Thus, 15.6 percent of net economic benefits would be the bonus amount.
- (h) For the purposes of calculating the bonus, the costs and benefits associated with DSM programs targeted to low-income customers may be excluded as follows:
- (l) the costs and benefits associated with a low-income DSM program may be excluded from the calculation of the net economic benefits for the entire DSM portfolio if the modified TRC value for the low-income program is below 1.0; and

- (II) the expenditures and therms saved associated with a low-income DSM program may be excluded from the calculation of the Savings Factor if the therms saved per dollar expended for the low-income program is below the approved savings target for the overall DSM portfolio.
- (i) The maximum bonus is 20 percent of net economic benefits or 25 percent of expenditures, whichever is less.
- (j) Any awarded bonus shall be authorized as a supplement to a utility and not count against its authorized rate of return or be considered in rate proceedings. The awarded bonus shall be recovered through the G-DSMCA over a 12-month period after approval of the bonus.

**4755. Measurement and Verification.**

- (a) Each utility shall implement a measurement and verification (M & V) program to evaluate the actual performance of its DSM program. The utility shall present its M & V plan as a part of its DSM plan application, pursuant to rule 4753, and shall include the complete M & V evaluation results with its annual DSM report in those years when the M & V is conducted.
- (b) As a part of its M & V program, the utility shall, at a minimum, design a M & V plan to evaluate the effectiveness of the actual DSM measures and programs implemented by the utility. The M & V plan shall address: sampling bias; a data gathering process sufficient to yield statistically significant results; and generally accepted methods of data analysis. The M & V plan shall also include an evaluation of free ridership, spillover and the net-to-gross ratio. The M & V evaluation shall be implemented at least once per the DSM plan period. Subsequent DSM plan applications shall reflect the results of all completed M & V evaluations.
- (c) The M & V evaluation shall, at a minimum, include the following:
  - (I) an assessment of whether the DSM programs have been implemented as set forth in its Commission approved DSM plan;
  - (II) a measurement of the actual energy savings for each DSM program, in dekatherms per dollar expended and in total dollars, and a comparison to the corresponding utility projections in the approved DSM plan;
  - (III) to the extent feasible, an assessment of the period of time that each DSM measure actually remains in service, and a comparison to the corresponding utility projections in the approved DSM plan;
  - (IV) a summary of the actual benefit/cost ratio for each DSM program within the approved DSM plan;
  - (V) an assessment of the extent to which education and market transformation efforts are achieving the desired results; and
  - (VI) recommendations for how the utility can improve the market penetration and cost effectiveness of individual DSM programs.

**4756. General Provisions Concerning Cost Allocation and Recovery.**

- (a) Amortization periods.
  - (I) For the base rate method, the utility shall propose the amortization period. The utility shall specify and explain the rationale for the amortization period proposed for each DSM program as a part of its DSM plan application, filed pursuant to rule 4753.
  - (II) For the expense method, the utility shall recover the annual expenditures projected for that year over a one-year period.
- (b) Fuel switching. Fuel switching from natural gas to other fossil fuel derived energy sources shall not be included in the gas utility's DSM program. Programs to save natural gas through switching to renewable energy sources such as solar heating and ground source heat pumps are allowed.
- (c) A utility that provides both regulated gas and electric service shall give consideration to the administrative benefits and reduced costs associated with combining gas and electric DSM activities and shall assign costs and benefits appropriately to each plan.
- (d) Distribution of DSM program expenses.
  - (I) The utility shall include in its portfolio-level benefit/cost analysis all indirect costs relating to DSM, including but not limited to DSM customer education, program design, and evaluation costs.
  - (II) A utility's existing gas efficiency and conservation customer education tools, such as on-line energy assessment tools or other similar internet based tools, may be included in a utility's gas DSM plan and costs recovered pursuant to the gas DSMCA rule.

**4757. Funding and Cost Recovery Mechanism.**

The purpose of the G-DSMCA is to enable utilities to recover prudently incurred gas DSM program expenses without requiring a change in their base rates for gas sales. All such costs, plus any G-DSM bonus approved by the Commission, shall be recovered through the G-DSMCA that is set on an annual basis, and collected from July 1 through June 30. The G-DSMCA allows for prospective recovery of prudently incurred costs of DSM programs within the DSM program expenditure target approved by the Commission in order to provide for funding of the utility's DSM programs, as well as recovery of deferred G-DSMCA costs, without having to file a rate case.

- (a) A utility may spend a disproportionate share of total expenditures on one or more classes of customers, provided, however, that cost recovery for programs directed at residential customers are to be collected from residential customers only and that cost recovery for programs directed at nonresidential customers are to be collected from nonresidential customers only, except as provided for in paragraph 4757 (f).
- (b) The utility may recover its DSM program expenditures either through expensing or by adding DSM program expenditures to base rates as a part of, or outside of, a rate case, with an amortization period as set forth in rule 4756.

- (c) There shall be no financial penalty assessed on a utility for failing to reach its approved DSM program expenditure target, nor shall there be a bonus simply for meeting its DSM program expenditure target. All prudently incurred expenditures for the utility's portfolio of DSM programs are recoverable. However, the portion of costs yielding a modified TRC test value below 1.0 loses its presumption of prudence and is subject to review.
- (d) Amounts not spent under the DSM program expenditure target shall not roll-over to the next DSM period.
- (e) A utility has the discretion and the responsibility of managing the portfolio of DSM programs to meet the benefit to cost ratio and the energy and savings targets. In implementing DSM programs, a utility shall use reasonable efforts to maximize energy savings consistent with the approved DSM plan.
- (f) A utility may continue DSM programs that were in existence on or before May 22, 2007, the effective date of § 40-3.2-103, C.R.S., concerning measures to promote energy efficiency, and shall not be required to obtain approval from the Commission for recovery of costs associated with such programs. Any new expenditure for such programs must be included in the annual DSM plan filing and G-DSMCA application. Existing low-income DSM programs that recover costs from all customer classes shall continue such recovery.
- (g) A utility shall file a request to adjust its G-DSMCA factor either through an application or an advice letter and tariffs, pursuant to the relevant provisions of title 40, articles 1 through 7 of the Colorado Public Utilities Law and of the Commission rules. The G-DSMCA shall be filed pursuant to the schedule provided in rule 4752.
- (h) The G-DSMCA filing shall include information and attachments as required in rule 4758. If the M & V evaluation required by rule 4755 yields benefit/costs test results that impact the allowable recovery of costs or currently approved bonus, then the utility shall include such adjustments in the G-DSMCA filing and tariffs.
- (i) If the projected DSM program costs have changed from those used to calculate the currently effective G-DSMCA cost or if a utility's deferred G-DSMCA cost balance increases or decreases sufficiently, the utility may file an application to revise its currently effective G-DSMCA factor to reflect such changes, provided that the resulting change to the G-DSMCA factor equates to a base rate change of at least one cent (\$0.01) per Mcf or Dth. A utility has the burden of proof to justify any interim G-DSMCA filings and the Commission has the discretion to consolidate the interim G-DSMCA filing with the next regularly scheduled annual G-DSMCA filing.
- (j) Applicability of the G-DSMCA factor. The G-DSMCA factor shall be separately calculated and applied to the utility sales gas base rate schedules of residential and non-residential customers.
- (k) Return on DSM program expenditures to be amortized. For utilities that choose to amortize the DSM program expenditure, the balance of a utility's investments in cost-effective DSM programs shall earn a return equal to the utility's current after-tax weighted average cost of capital.



- (l) Interest on under- or over-recovery. The amount of net interest accrued on the average monthly balance in sub-accounts of Account No. 186 (whether positive or negative), is determined by multiplying the monthly balance by an interest rate equal to the Commission-authorized after-tax weighted average cost of capital.
- (m) Calculation of the G-DSMCA factor. The G-DSMCA factor shall be calculated separately for residential and non-residential customers to at least the accuracy of two significant places.

**4758. Contents of Gas DSM Cost Adjustment Filing.**

- (a) General Provisions.
  - (I) A filing for a gas DSM cost adjustment (G-DSMCA) shall contain justifying information sufficient in detail to permit the Commission to determine the accuracy of the supporting calculation.
  - (II) The G-DSMCA filing shall include a complete set of work papers and all other documents relied on in preparing the adjustment.
  - (III) The provisions of this rule do not supersede other Commission rules that contain additional applicable filing requirements.
- (b) Specific Provisions. The filing shall contain detailed schedules and supporting documents that establish, at a minimum, the following:
  - (I) the detailed calculation of the G-DSMCA for each customer class based on the following general formula:
    - (A)  $\text{current G-DSMCA factor} = (\text{current G-DSMCA cost} + \text{deferred G-DSMCA cost}) / (\text{forecasted sales customer} \times \text{monthly service charge} + \text{forecasted sales gas quantity} \times \text{base rate});$  and
    - (B) the G-DSMCA factor will also include the current G-DSM bonus plus any adjustment necessary to previously approved G-DSM bonuses;
  - (II) a detailed schedule showing the computation of interest, as applicable, to deferred amounts;
  - (III) the absolute and percentage impact of the proposed rate on the base rates and on the total monthly bills of typical customers in each customer class;
  - (IV) a schedule detailing the allocation of costs to each customer class;
  - (V) proposed customer notice detailing rate impact and effective date;
  - (VI) proposed tariff implementing the proposed G-DSMCA; and

- (VII) if any gas DSM costs are proposed to be recovered by rate base treatment, with a return on the unamortized balance, a statement of current net operating earnings, a detailed calculation of the related revenue requirement and an attachment detailing any differences in the proposed rate base treatment compared to the regulatory practices employed by the Commission in its last general rate case for the applicant.

**4759. Bill Itemization.**

Consistent with rule 4406, a utility shall provide itemized gas cost information with gas DSM costs to all customers commencing with the first complete billing cycle in which the new rates are in effect.

**4760. Gas DSM Bonus (G-DSM Bonus) Applications.**

The Commission shall review each G-DSM bonus application submitted and shall determine the level of bonus, if any, for which the utility is eligible. The collection on any G-DSM bonus awarded will be apportioned between residential and nonresidential customers based on the proportion of residential and nonresidential net economic benefits used to calculate the G-DSM bonus.

- (a) G-DSM bonus filing requirements. The utility shall file its G-DSM bonus application as part of the annual report submitted to the Commission on the timetable set forth in rule 4752. The utility may request a G-DSM bonus not to exceed the lower of 25 percent of the expenditures or 20 percent of the net economic benefits of the DSM programs, applying the bonus calculation procedure set forth in rule 4754. The G-DSM bonus, as modified and approved by the Commission, shall not count against a gas utility's authorized rate of return or be considered as net operating earnings in rate proceedings.
- (b) Contents of G-DSM bonus filing. In the G-DSM bonus filing, the utility shall submit to the Commission the following, at a minimum:
  - (I) documented expenditures on DSM programs for the current G-DSMCA period;
  - (II) gas savings for the calendar year for which the bonus is to be awarded estimated following and the techniques approved in the DSM plan. The utility shall explain whether the actual gas savings are validated through the measurement and verification process as approved in the utility's DSM plan;
  - (III) estimated cost-effectiveness of program expenditures for the current G-DSMCA period in terms of the amount of gas saved per unit of program expenditures;
  - (IV) actual gas savings and the techniques used to calculate these gas savings for the prior G-DSMCA period. The utility shall explain whether the actual gas savings are validated through the measurement and verification process, pursuant to rule 4755;
  - (V) actual cost-effectiveness of program expenditures for the prior G-DSMCA period in terms of the amount of gas saved per unit of program expenditures. The utility shall explain whether the actual cost effectiveness of program expenditures is validated through the measurement and verification process, pursuant to rule 4755; and
  - (VI) proposed tariffs containing rates to collect the bonus over 12 months.

- (c) The Commission shall issue a decision approving, modifying, or disapproving a DSM bonus application within 90 days of the utility filing of the application. The Commission shall allow oral testimony and shortened discovery response times as necessary to expedite the schedule.
- (d) Accounting for G-DSM bonus. Accounting for G-DSM bonus shall follow what has been prescribed for G-DSMCA costs, specifically in regard to interest on over- and under- recovery. A separate sub-account in Account No. 186 shall be created for any deferred G-DSM bonus amount.
- (e) Prudence review and adjustment of G-DSM bonus. If the Commission finds that the actual performance varies from performance values used to calculate the G-DSM bonus in rule 4754, then an adjustment shall be made to the amount of G-DSM bonus award. Any true-up in G-DSM bonus will be implemented on a prospective basis.

**4761. – 4799. [Reserved]**

**MASTER METER OPERATORS**

**4800. Scope and Applicability.**

These rules are applicable to any person who purchases gas service from a serving utility for the purpose of delivery of that service to end-users whose aggregate usage is measured by a master meter or other composite measurement device.

**4801. Definitions.**

The following definitions apply to rules 4800 through 4805, unless a specific statute or rule provides otherwise. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- (a) "Check-meter" means a meter or other composite measurement device used by a master meter operator to determine gas consumption by end-users served by the master meter operator.
- (b) "Master meter" means a meter or other composite measurement device which a serving utility uses to bill a master meter operator.
- (c) "Master meter operator" (MMO) means a person who purchases gas service from a serving utility for the purpose of delivering that service to end-users whose aggregate usage is measured by a master meter.
- (d) "Refund" means a refund, rebate, rate reduction, or similar adjustment.
- (e) "Serving utility" means the utility from which the master meter operator receives the gas service which the master meter operator then delivers to end-users.

**4802. Exemption from Rate Regulation.**

- (a) Pursuant to § 40-1-103.5, C.R.S., and by this rule, the Commission exempts from rate regulation under Articles 1 to 7 of Title 40, C.R.S., a master meter operator which is in compliance with rules 4803 and 4804.
- (b) A master meter operator which is not in compliance with rules 4803 and 4804 is subject to rate regulation under Articles 1 to 7 of Title 40, C.R.S., and shall comply with the applicable rules.

**4803. Exemption Requirements.**

- (a) In order to retain its exemption from rate regulation, a MMO shall do the following.
  - (I) As part of its billing for utility service, the MMO shall charge its end-users only the actual cost billed to the MMO by the serving utility. The MMO shall not charge end-users for any other costs (such as, without limitation, the costs of construction, maintenance, financing, administration, metering, or billing for the equipment and facilities owned by the MMO) in addition to the actual costs billed to the MMO by the serving utility.
  - (II) If the MMO bills its end-users separately for service, the sum of such billings shall not exceed the amount billed to the MMO by the serving utility.
  - (III) If the MMO bills its end-users separately for service, the MMO shall pass on to its end-users all refunds the MMO receives from the serving utility or otherwise.
  - (IV) The MMO shall establish procedures for giving notice of a refund to those who are not current end-users but who were end-users during the period for which the refund is paid.
  - (V) A master meter operator shall retain, for a period of not less than three years, all records of original utility billings made to the master meter operator and all records of billings and refunds made by the master meter operator to its end-users, including certification of mailing, when applicable.
- (b) In order to retain its exemption from rate regulation, a MMO shall not resell the services provided by a serving utility to the MMO for profit. Resale of services provided by a serving utility to a MMO for profit is a basis for revocation of an exemption from rate regulation.
- (c) A MMO may check-meter tenants, lessees, or other persons to whom the gas ultimately is distributed but may do so only if the following conditions are met:
  - (I) the check-meter is used solely for the purpose of determining a basis for the MMO to allocate the costs of the serving utility; and
  - (II) the MMO does not receive more than the actual amount billed to the MMO by the serving utility from the MMO's customers.

**4804. Refunds.**

- (a) When a serving utility notifies a MMO of a refund or when a refund is otherwise made related to the services provided by the serving utility to the MMO, a MMO shall refund an allocated share of the refunds to its customers within 90 days after receipt of the notice or refund from the serving utility. The notification shall be made either by first-class mail with a certificate of mailing or by inclusion in any monthly or more frequent regular written communication. The MMO shall retain the certification of mailing pursuant to subparagraph 4803(a)(V). The MMO shall also notify former customers who were end-users during the period for which the refund is made that refunds are available, to the extent such former customers can be located.
- (b) A MMO may retain any portion of a refund which is related to service taken by the MMO at its own facilities after refunds are made to its current and former customers.
- (c) If the aggregate amount of a refund which remains unclaimed after 90 days exceeds \$100, the MMO shall contribute that unclaimed amount to the energy assistance organization in accordance with rules 4410(d), (f), and (g). If the aggregate amount which remains unclaimed after 90 days does not exceed \$100, the MMO may retain the aggregate amount.

**4805. Complaints, Penalties, and Revocation of Exemption.**

- (a) Pursuant to rules 1301 and 1302, a person (including without limitation anyone taking service from a master meter operator) may make an informal complaint to the Commission or may file a formal complaint with the Commission with the respect to an alleged violation of rules 4803 and 4804.
- (b) As a result of a complaint or on its own motion, the Commission will investigate complaints concerning MMOs. If the Commission determines after investigation that an MMO has violated any of the requirements of rules 4803 and 4804, the MMO may have its exempt status revoked or may be subject to penalties as set forth in § 40-7-107, C.R.S., or both.

**4806. – 4975. [Reserved].**

**4976. Regulated Gas Utility Rule Violations, Civil Enforcement, and Civil Penalties.**

An admission to or Commission adjudication for liability for an intentional violation of the following may result in the assessment of a civil penalty of up to \$2,000.00 per offense. Fines shall accumulate up to, but shall not exceed, the applicable statutory limits set in § 40-7-113.5, C.R.S.

Citation	Description	Maximum Penalty Per Violation
	Articles 1-7 of Title 40, C.R.S.	\$2000
	Commission Order	\$2000
Rule 4005	Records and Record Retention	\$2000

Rule 4027(a)	Collection and Use of Customer Data	\$1000
Rule 4027(b),	Disclosure of Customer Data	\$2000
Rule 4027(c)	Tariff	\$1000
Rule 4027(d)	Disclosure of Customer Data	\$1000
Rule 4028(a)	Customer Notice	\$1000
Rule 4029(a),(b)	Consent Form	\$1000
Rule 4030(a)	Disclosure of Customer Data	\$2000
Rule 4030(b)	Records	\$1000
Rule 4031(a)	Disclosure of Customer Data	\$2000
Rule 4031(b)	Records	\$1000
Rule 4032(a)	Disclosure of Customer Data	\$2000
Rules 4032(c) and (d)	Consent and Records	\$1000
Rule 4033(a)	Disclosure of Aggregated Data	\$2000
Rule 4033(d)	Tariff	\$1000
Rule 4100(a)	Obtaining a Certificate of Public Convenience and Necessity for a Franchise	\$2000
Rule 4101(a)	Obtaining a Certificate of Public Convenience and Necessity or Letter of Registration to operate in a service territory	\$2000
Rule 4102(a)	Obtaining a Certificate of Public Convenience and Necessity for facilities	\$2000
Rule 4103(a), (c), (d)	Amending a Certificate of Public Necessity for changes in service territory or facilities	\$2000
Rule 4108(a), (c)	Keeping a Current Tariff on File with the Commission	\$2000
Rule 4109	Filing a New or Changed Tariff with the Commission	\$2000

Rule 4110(b),(c)	Filing an Advice Letter to Implement a Tariff Change	\$2000
Rule 4200	Construction, Installation, Maintenance and Operation of Facilities in Compliance with Accepted Engineering and Industry Standards	\$2000
Rule 4208	Anticompetitive Conduct and Unacceptable Practices	\$2000
Rule 4210	Line Extensions	\$2000
Rule 4303	Meter Testing	\$2000
Rule 4306	Record Retention of Tests and Meters	\$2000
Rule 4309	Provision of Written Documentation of Readings and Identification of When Meters Will be Read	\$2000
Rule 4401	Billing Information, Procedures, and Requirements	\$2000
Rule 4754(a)-(e)	Annual DSM Report and Application for Bonus and Bonus Calculation	\$2000
Rule 4803(c)	Master Meter Exemption Requirements	\$2000
Rule 4004(b)-(f)	Disputes and Informal Complaints	\$1000
Rule 4202	Maintaining Heating Value, Purity and Pressure Standards	\$1000
Rule 4203(a)-(f)	Trouble Report Response, Interruptions and Curtailments of Service	\$1000
Rule 4405	Provision of Service, Rate, and Usage Information to Customers	\$1000
Rule 4406	Provision of Gas Cost Component Information to Customers	\$1000
Rule 4603(a),(d)	Gas Cost Adjustments	\$1000
Rule 4605(a),(b),(e),(f)	Gas Purchase Plans	\$1000

Rule 4607(a)	Gas Purchase Reports and Prudence Reviews	\$1000
Rule 4403(a)-(q)	Applications for Service, Customer Deposits, and Third Party Guarantees	\$500
Rule 4006	Annual Reporting Requirements	\$100
Rule 4304	Scheduled Meter Testing	\$100
Rule 4305	Meter Testing Upon Request	\$100
Rule 4402(a),(c),(d)	Meter and Billing Error Adjustments	\$100
Rule 4404(a)-(f)	Availability of Installation Payments to Customers	\$100
Rule 4407	Discontinuance of Service	\$100
Rule 4408(a)-(g); (i)	Notice of Discontinuation of Service	\$100
Rule 4409	Restoration of Service	\$100
Rule 4411(c)(IV),(d)(I), d(II),(e)	Low-Income Energy Assistance Act	\$100

**4977. – 4999. [Reserved].**

**GLOSSARY OF ACRONYMS.**

CAAM –	Cost Allocation and Assignment Manual
CCR –	Colorado Code of Regulations
C.F.R. –	Code of Federal Regulations
CPCN -	Certificate of Public Convenience and Necessity
CRCP –	Colorado Rules of Civil Procedure
C.R.S. -	Colorado Revised Statutes
e-mail -	Electronic mail
FDC -	Fully Distributed Cost
FERC –	Federal Energy Regulatory Commission
GAAP -	Generally Accepted Accounting Principles
GCA –	Gas Cost Adjustment
GPP –	Gas Purchase Plan
GPR –	Gas Purchase Report
ITP –	Intrastate Transmission Pipeline
LDC –	Local Distribution Company



MMO – Master Meter Operator  
OCC - Office of Consumer Counsel  
USOA – Uniform System of Accounts

**Glossary of Gas Measurement Units:**

Btu – British Thermal Unit  
MMBtu – 1,000,000 Btu (approximately one Mcf, depending on heat content of gas)  
Dth – Dekatherm or One MMBtu  
Therm – 100,000 Btu (approximately one Ccf, depending on heat content of gas)  
Scf - Standard cubic feet  
Ccf – 100 cubic feet (typically actual cf at meter, rather than Scf)  
Mcf – 1,000 standard cubic feet  
MMcf – 1,000,000 standard cubic feet  
Bcf – 1,000,000,000 standard cubic feet  
MMcfd – One MMcf per day

## **COLORADO DEPARTMENT OF REGULATORY AGENCIES**

### **Public Utilities Commission**

#### **4 CODE OF COLORADO REGULATIONS (CCR) 723-11**

##### **PART 11**

#### **RULES REGULATING PIPELINE OPERATORS AND GAS PIPELINE SAFETY**

##### **BASIS, PURPOSE, AND STATUTORY AUTHORITY**

The purpose of these rules is to describe the requirements for the safe operation of jurisdictional gas pipeline facilities, including construction, operations, maintenance, and operator reporting. These rules outline how the Commission will conduct pipeline safety program activities and complete the Commission's Program Certification Obligations.

The statutory authority for the promulgation of these rules can be found at §§ 40-1-103, 40-2-108, 40-2-115, 40-3-110, 40-4-109, 40-6-108, and 40-7-117, C.R.S.

##### **GENERAL PROVISIONS**

###### **11000. Scope and Applicability.**

- (a) Absent a specific statute, rules or Commission order that provides otherwise, all rules in this Part 11 (the 11000 series) shall apply to all public utilities and all municipal or quasi-municipal corporations transporting natural gas or providing natural gas service, all operators of master meter systems, and all operators or pipelines transporting gas in interstate commerce, as defined in 49 C.F.R. § 191.3.
- (b) The Public Utilities Commission conducts its Pipeline Safety Program (PSP) activities under §§ 40-1-103, 40-2-115, and 40-7-117, C.R.S. These provide the state statutory authority permitting the Commission to enter into cooperative agreements with federal agencies and to adopt and create rules to administer and to enforce the Natural Gas Pipeline Act found at 49 U.S.C. §§ 60101, et. seq. Collectively, the above referenced federal code and state statutes comprise the Commission's Program Certification Obligations.
- (c) These gas pipeline safety rules prescribe the Commissions' requirements for:
  - (I) the safe construction, operation, maintenance, and integrity management of:
    - (A) all intrastate pipeline facilities engaged in the transportation of hazardous gases, including natural gas and vaporized liquefied petroleum (LP) gas; and
    - (B) liquefied natural gas (LNG) facilities; and
  - (II) reporting requirements for operators of all facilities and pipeline systems.

- (d) These rules apply to establish and govern:
  - (I) regulations and standards for the safe transportation of hazardous gases by intrastate pipeline in Colorado;
  - (II) administration of the pipeline safety regulations by the Commission;
  - (III) reporting to the Commission by operators of specific information related to pipeline safety; and
  - (IV) adoption of federal minimum safety standards for transportation of natural gas and other gas by pipeline including:
    - (A) adoption of federal minimum safety standards for LNG facilities; and
    - (B) adoption of federal drug and alcohol testing regulations and procedures.
- (e) Except as otherwise directed, processes provided in the Commission’s Rules of Practice and Procedure, 4 CCR 723-1, including the rules governing confidentiality, shall apply to all filings made pursuant to this Part 11.
- (f) Consistent with § 40-15-107(2)(a), C.R.S., all information, documents, and copies of documents provided in connection with an audit, including any Request for Information from the PSP Chief or PSP Staff, shall be treated as confidential and shall not be made public by the Commission or any other person without prior written consent of the person providing such information, documents, or copies; or pursuant to a court order issued pursuant to § 24-72-204(5), C.R.S. If any such information, document, or copy of a document becomes the basis for, or employed within, an enforcement action pursuant to rule 11500 et seq., rules 1100-1103 of the Commission’s Rules of Practice and Procedure shall govern any claim of confidentiality in such proceeding. Any such information, document, or copy of a document that is not treated as, or deemed, confidential or highly confidential in any such proceeding thereafter shall not be treated by the Commission as confidential for any other purpose.
- (g) Nothing in these rules shall be construed to exempt pipeline operators from complying with § 9-1.5-105, C.R.S.

**11001. Definitions.**

The following definitions apply throughout this Part 11, except where a specific rule or statute provides otherwise or where the context otherwise indicates. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- (a) “C.F.R.” means the Code of Federal Regulations.
- (b) “Confirmed discovery” means a discovery defined, as of the effective date of these rules, in 49 C.F.R. § 191.3.
- (c) “Continuing violation” or “time-dependent violation” means any violation of these rules for which a timeframe of non-compliance can be established through physical evidence and/or records that

include, but are not limited to: operator annual reports; operator compliance, operations, and maintenance records; and commission inspection, compliance and proceeding records.

- (d) “Delivered system pressure” means the system operating pressure measured at the outlet of the furthest downstream appurtenance maintained by the pipeline system operator, e.g., regulator, meter, valve, or the terminal connection of the service riser in low-pressure distribution systems.
- (e) “De minimis gas system” means a non-utility underground pipeline system used for transport and distribution of natural gas to less than ten customers within a definable private (i.e., non-municipal or public) area (e.g., a mobile home park or resort) and that does not cross a public right-of-way.
- (f) “Direct sales meter” means a meter that measures the transfer of gas to a direct sales customer purchasing gas for consumption.
- (g) “Direct sales pipeline” means a pipeline not under the jurisdiction of the Federal Energy Regulatory Commission and that runs from an intrastate or interstate transmission pipeline, a production facility, or a gathering pipeline to a direct sales meter, a pressure regulator, or an emergency valve, whichever is the furthest downstream.
- (h) “Excavation damage” means any impact that results in the need to repair or replace an underground facility due to a weakening or the partial or complete destruction of a facility, including, the protective coating; plastic pipe tracer wire; lateral support; cathodic protection; or the housing for the line device or facility
- (i) “Gas” means any material specified in these rules, including natural gas, flammable gas, toxic or corrosive gas, and petroleum gas.
- (j) “Gathering pipeline” means any pipeline determined through the use of 49 C.F.R. § 192.8.
- (k) “Hazardous facility” means a pipeline facility that, if allowed to go into operation or to remain in operation, would pose a severe or imminent risk to public safety.
- (l) “Incident” means an event defined as of the effective date of these rules, in 49 C.F.R. § 191.3, for a pipeline facility covered by 49 C.F.R. Part 192 or an emergency, as defined in § 193.2007 for an LNG facility.
- (m) “Liquefied natural gas” (LNG) means natural or synthetic gas that has methane (CH<sub>4</sub>) as its major constituent and that has been converted to liquid form for purposes of storage or transport.
- (n) “Liquid petroleum gas (LPG) system” means the liquid petroleum (LP) tanks and/or the pipeline system used to transport and distribute LP fuel gas to ten or more customers within a definable private (i.e. non-municipal or public) area (e.g., a mobile home park or resort), or less than ten customers if the system crosses a public right-of-way. LPG systems may have multiple operators if the supplying tank(s) is/are operated and maintained distinctly from the pipeline system by a different owner.
- (o) “Low-pressure distribution system” means a gas distribution system in which the gas pressure in the main is substantially the same as the pressure provided to the customer, i.e., the low-

pressure gas burning equipment of the customer may be safely and continually operated at the delivered system pressure.

- (p) “LPG Tank – CDLE OPS Inspected” means any LPG tank inspected by the Colorado Department of Labor and Employment, Division of Oil and Public Safety under the authority of the OPS rules.
- (q) “LNG facility” means a pipeline facility that is used for liquefying natural or synthetic gas and/or for transferring, storing, or vaporizing liquefied natural gas.
- (r) “Main” means a distribution line that serves, or is designed to serve, as a common source of supply for more than one service line.
- (s) “Major master meter operator (MMO)/LPG system” refers to any MMO or LPG pipeline system serving 100 or more customers.
- (t) “Mechanical excavation” means any operation in which earth is moved or removed by means of any tools, equipment, or explosives and includes auguring, backfilling, boring, ditching, drilling, grading, plowing-in, pulling-in, ripping, scraping, trenching, hydro-excavating, post/postholing, and tunneling.
- (u) “MMO gas system” means a non-utility pipeline system used for transport and distribution of natural gas to ten or more customers within a definable private (i.e., non-municipal or public) area (e.g., a mobile home park or resort), or less than ten customers if the system crosses a public right-of-way.
- (v) “Minor MMO/LPG system” means any MMO or LPG pipeline system serving between 20 and 99 customers.
- (w) “Municipality” means a city, town, or village in the state of Colorado.
- (x) “NRC” means the National Response Center of the United States Coast Guard.
- (y) “NTSB” means the National Transportation Safety Board, an independent federal agency.
- (z) “Natural Gas Pipeline Act” means the federal statute found at 49 U.S.C. §§ 60101 et seq., as amended.
- (aa) “No immediate safety impact” refers to action or inaction by operator/operator contractors on jurisdiction pipeline facilities that resulted in no immediate or imminent hazard to either the public, operator/operator contractor personnel, or pipeline system integrity.
- (bb) “Operator” means a person who is engaged in the transportation of gas, or who has the right to bury underground pipeline, or who is both engaged in the transportation of gas and has the right to bury underground pipeline, and may include an owner, such as a pipeline corporation.
- (cc) “Operator contractor” means any person or entity empowered by an operator to perform any action covered by 49 C.F.R. Part 192 and these rules.

- (dd) “Operator endangerment” refers to action or inaction by operator/operator contractors on pipeline facilities that resulted in an immediate or imminent hazard to operator/operator contractor personnel.
- (ee) “OPS” means the Office of Pipeline Safety, a unit of the PHMSA.
- (ff) “Part 192” means 49 C.F.R. Part 192 – Transportation of natural and other gas by pipeline: Minimum Federal safety standards.
- (gg) “Person” means an individual, firm, joint venture, partnership, corporation, association, municipality, cooperative association, or joint stock association, and includes any trustee, receiver, assignee, or personal representative thereof.
- (hh) “Petroleum gas” means propane, propylene, butane, (normal butane or isobutanes), and butylene or mixtures composed predominately of these gases.
- (ii) “PHMSA” means the Pipeline and Hazardous Materials Safety Administration, an agency of the United States Department of Transportation.
- (jj) “Pipeline” or “pipeline system” means all parts of those physical intrastate facilities through which gas moves in transportation, including, but not limited to, pipes, valves, and other appurtenances attached to pipes, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies that start downstream beyond the farthest most point of oil and gas production. Flowlines that are regulated by the COGCC and used for oil and gas production are not included in this definition.
- (kk) “Pipeline excavation damage prevention program” means an operator’s written program and processes to prevent damage to a pipeline by excavation, as defined in 49 C.F.R. § 192.614.
- (ll) “Pipeline facility” means new and existing intrastate pipelines, rights-of-way, and any equipment, facility, or building used in the transportation of gas, or in the treatment of gas during transportation.
- (mm) “Pipeline integrity” means the ability of a pipeline system to operate as it was verifiably designed and constructed.
- (nn) “Pipeline safety program” (PSP) means the Commission’s 49 U.S.C. § 60105(a) certified pipeline safety program.
- (oo) “Production facility” means flowline and associated equipment used at a wellsite in producing, extracting, recovering, lifting, stabilizing, initial separating, treating, initial dehydrating, disposing, and/or above ground storing, of liquid hydrocarbons, associated liquids, and associated natural hydrocarbon gases. A production facility may include flowlines up to a central delivery point directly associated with a specific producing field. To be a production facility under this rule, a flowline must be used in the process of extracting hydrocarbons and associated liquids from the ground or from facilities where hydrocarbons are produced or must be used for disposal or injection in reservoir maintenance or recovery operations.

- (pp) “PSP Chief” means the program manager of the PHMSA certified PSP of the Colorado Public Utilities Commission.
- (qq) “PSP Lead Engineer” means the senior technical staff member of the PHMSA certified PSP of the Colorado Public Utilities Commission.
- (rr) “PSP Staff” means a staff member of the PHMSA certified PSP of the Colorado Public Utilities Commission.
- (ss) “Program certification obligations” means the pipeline safety program obligations required under 49 U.S.C. § 60105(a).
- (tt) “Public endangerment” means an action or inaction by an operator/operator contractor on pipeline facilities that results in:
  - (I) interruption or delay of make safe actions designed to protect human life;
  - (II) unintended gas release requiring emergency (versus precautionary) evacuation of the public;
  - (III) an unsafe ignition of intended gas release in an area accessible to the public;
  - (IV) system overpressurization event/failure of system overpressure protection requiring emergency (versus precautionary) evacuation of the public; or
  - (V) any other hazardous situation that results in an immediate or imminent hazard to the public.
- (uu) “Roadway” means a main public artery, highway, or interstate highway.
- (vv) “Related violation” for purposes of informing the Commission authority pursuant to § 40-7-117, C.R.S., means a violation of these rules that has been proven to be directly linked with a PUC rule violation or violations by time, place, activity, and/or personnel.
- (ww) “Request for Information (RFI)” means any request from the PSP Chief or assignee to a jurisdictional operator for information associated with PSP inspection activities authorized by paragraph 11013(a).
- (xx) “Rural gathering pipeline” means any gathering pipeline located in a Class 1 location and defined in 49 C.F.R. § 192.5 or a Type B gathering pipeline located in a Class 2 area that the operator determines does not meet the Area 2 dwelling density definition in 49 C.F.R. § 192.8.
- (yy) “Single structure, above-ground MMO/LPG system” or “SSAG System” means any MMO or LPG system that is:
  - (I) a low-pressure gas distribution system;
  - (II) is comprised wholly of above-ground piping/appurtenances; and

- (III) is contained wholly within or on a single continuous structure such as an apartment building, hotel, mall, etc.
- (zz) “Small operator” means any gas distribution system operator that operates less than 1000 natural gas distribution services in the state of Colorado.
- (aaa) “Threshold MMO/LPG system” means any MMO or LPG pipeline system serving less than 20 customers.
- (bbb) “Transportation of gas” means the gathering, transmission, distribution, or storage of gas within the State of Colorado that is not subject to the jurisdiction of the Federal Energy Regulatory Commission under the Natural Gas Act.
- (ccc) “UNCC/Colorado 811” means the Utility Notification Center of Colorado.

**11002. – 11007. [Reserved].**

**11008. Incorporation by Reference.**

- (a) The Commission incorporates by reference the federal standards for reporting safety-related conditions associated with the transportation of natural gas and other gas by pipeline published in 49 C.F.R. § 191.23 (reporting safety-related conditions) and § 191.25 (filing safety-related condition reports); effective October 1, 2019. This incorporation by reference does not include later amendments to, or editions of, 49 C.F.R. Part 191.
- (b) The Commission incorporates by reference the federal safety standards for the transportation of natural gas and other gas by pipeline published in 49 C.F.R. Part 192 effective October 1, 2019. This incorporation by reference does not include later amendments to, or editions of, 49 C.F.R. Part 192.
- (c) The Commission incorporates by reference the federal safety standards for liquefied natural gas facilities that are published in 49 C.F.R. Part 193 effective October 1, 2019. This incorporation by reference does not include later amendments to, or editions of, 49 C.F.R. Part 193.
- (d) The Commission incorporates by reference the drug and alcohol testing regulations and procedures of PHMSA published in 49 C.F.R. Parts 40 and 199 effective October 1, 2019. This incorporation by reference does not include later amendments to, or editions of, 49 C.F.R. Parts 40 and 199.
- (e) Any material incorporated by reference in this Part 11 may be examined at the offices of the Commission, 1560 Broadway, Suite 250, Denver, Colorado 80202, during normal business hours, Monday through Friday, except for state holidays. Incorporated standards shall be available electronically and provided in certified copies, at cost, upon request. Restrictions on the provision of physical copies due to copyright protections may apply. The Director or the Director’s designee will provide information regarding how the incorporated standards may be examined at any state public depository library. The standards and regulations are also available from the agency, organization or association originally issuing the code, standard, guideline or rule as follows: Code of Federal Regulations: [www.govinfo.gov/help/cfr](http://www.govinfo.gov/help/cfr).



**11009. Conflict.**

In the event of a conflict regarding any administrative, enforcement, or reporting requirement of 49 C.F.R. Parts 40, 192, 193, and/or 199 and Commission Pipeline Safety Rules, the Commission's rules shall apply.

**11010. Interpretation.**

- (a) Consistent with rule 1304 of the Commission Rules of Practice and Procedure, 4 CCR 723-1, an operator may file a petition seeking a declaratory order that resolves a controversy or uncertainty regarding any statute, Commission rule, regulation, and/or Commission decision. The requestor shall include with each request, at least the following:
  - (I) the statutory provision(s), Commission rule(s), regulation(s), and/or decision(s) at issue;
  - (II) the specific instance or illustration of the application of the statutory provision(s), Commission rule(s), regulation(s), and/or decision(s) that causes the controversy or uncertainty; and
  - (III) the complete petitioner's contact information.
  - (IV) The petition may also include a request for expedited treatment if an interpretation is needed quickly and good cause exists.
- (b) Upon receipt of the petition for a declaratory order, the Commission will consider whether to accept the filing consistent with rule 1304 of the Commission's Rules of Practice and Procedure, 4 CCR 723-1.
- (c) If the petition requires interpretation of a federal regulation incorporated by reference into these rules and the Commission accepts the petition, PHMSA must review the Commission's interpretation of the federal regulation. The Commission's decision interpreting the federal regulation, and the reasons therefor, shall issue as an interim decision that shall be provided to the Office of Pipeline Safety for final review. Any response by the Office of Pipeline Safety shall be incorporated into the Commission's final decision.
- (d) Nothing in these rules prohibits an operator from contacting the PSP Chief or PSP Lead Engineer for informal assistance. Consistent with paragraph 1007(d) of the Commission's Rules of Practice and Procedure, 4 CCR 723-1, opinions expressed by the PSP Chief or PSP Lead Engineer do not represent the official views of the Commission, but are designed to aid the public and to facilitate the accomplishment of the Commission's functions. Nothing communicated by the PSP Chief or PSP Lead Engineer constitutes legal advice.

**11011. Waiver – Non-emergency.**

- (a) An owner or operator may request a waiver or a variance from any of these rules in accordance with § 40-2-115, C.R.S., 49 U.S.C. § 60118(d), and paragraph 1003(b) of the Commission's Rules of Practice and Procedure 4 CCR 723-1. Requests for waiver from the standards in 49 C.F.R. Part 192 that are incorporated by reference into these rules are subject to paragraph (c) below.

- (b) The petition shall include:
- (I) information required by rule 1003 paragraph (c);
  - (II) the specific instance or illustration of the rule's application requiring modification/waiver;
  - (III) proposed alternatives to compliance with the regulation (e.g., additional inspections and tests, shortened reassessment intervals, etc.);
  - (IV) an explanation of the necessity with supporting evidence and documentation, including:
    - (A) the mileage or footage of pipeline to be covered and the counties in which it is located;
    - (B) a description of the pipeline(s) affected by the permit (e.g., year installed, material, thickness, diameter, operating pressure, etc.);
    - (C) all pipeline other facilities such as pump and compressor stations that the permit will affect; and
    - (D) other pertinent operational history/data (e.g., leak history, corrosion history, etc.);
  - (V) a certification that the modification/waiver is consistent with pipeline safety; and
  - (VI) the complete operator contact information.
- (c) An owner or operator may file a petition for waiver to deviate from the standards in 49 C.F.R. Part 192 that are incorporated into these rules and alter the frequency of periodic inspections and tests on the basis of an engineering analysis and risk assessment.
- (I) A request for waiver for an alternative frequency of inspections and tests required under Part 192 will be granted if the request is found to be not inconsistent with pipeline safety. For intrastate facilities, an operator must file its proposal as a petition for waiver through the Commission's E-Filings System at least 120 days before the requested effective date.
  - (II) An owner or operator may implement an approved reduction in the frequency of a periodic inspection or test only where the operator has developed and implemented an integrity management program that provides an equal or improved overall level of safety despite the request for reduced frequency of periodic inspections.
  - (III) In addition to the information in subparagraph (b) above, each petition filed under this subsection must include the following information:
    - (A) name of the owner or operator;
    - (B) duration of the deviation proposal;
    - (C) specific regulations from which the owner or operator seeks relief;

- (D) a description of the pipeline for which the deviation is sought, including:
    - (i) the mileage or footage of the pipeline to be covered by the request and the counties in which it is located;
    - (ii) the year the pipeline was installed;
    - (iii) all pipeline facilities that the request will affect; and
    - (iv) the material, thickness, diameter, and operating pressure of the pipeline;
  - (E) alternatives proposed for compliance with the regulation (e.g., additional inspections and tests, shortened reassessment intervals); and
  - (F) a certification that operation of the owner or operator's pipeline under the requested alternative frequency of periodic inspections and tests would not be inconsistent with pipeline safety and will provide an equal or greater overall level of safety.
- (IV) After receiving notice of the petition, the PSP Chief will confer with the Office of Pipeline Safety on the waiver requested by the owner or operator. The PSP Chief will file a notice in the petition proceeding indicating whether the request should be accepted by the Commission and if so, whether additional conditions or limitations that are relevant and in the public interest should be adopted. The Commission shall consider the petition for waiver and the notice filing of the PSP Chief in rendering a decision.
- (d) PHMSA Review: If the Commission grants a petition filed by an owner/operator for a waiver of a federal rule that is incorporated into the Commission rules, PHMSA must review the Commission's decision. The Commission's decision granting the waiver request, and the reasons therefor, shall issue as an interim decision that shall be provided to the Office of Pipeline Safety for final review pursuant to 49 U.S.C. § 60118(d). Any response by the Office of Pipeline Safety shall be incorporated into the Commission's final decision.

**11012. Waiver – Emergency.**

- (a) An operator may file a petition to request an emergency waiver or variance in situations that require expedited review that is otherwise inconsistent with § 40-2-115, C.R.S., 49 U.S.C. § 60118(d), and the Commission's Rules of Practice and Procedure.
- (b) An emergency waiver request will be granted if it is in the public interest, is not inconsistent with pipeline safety, and is necessary to address an actual or impending emergency involving pipeline transportation, including emergencies caused by natural or manmade disasters.
- (c) An emergency waiver is an order by which the Commission may temporarily modify compliance with state pipeline regulations for affected pipeline owners or operators and the Commission may waive compliance with a safety regulation if, after receiving notice on an incorporated federal rule, PHMSA concurs in the action.

- (d) The Commission will determine on a case-by-case basis what duration of waiver or variance is necessary to address the emergency. However, as required by statute, no emergency waiver may be issued for a period exceeding 60 days. Each emergency waiver will automatically expire on the date stated in the Commission's decision.
- (e) An operator may request an emergency Special Permit modifying or waiving of any of these rules by submitting a written request as follows.
  - (I) If the request concerns a Colorado-specific rule then no subsequent review by PHMSA is required. The requestor shall file a petition for the emergency waiver with the Commission using one of the following methods:
    - (A) the Commission's E-Filings System; or
    - (B) express mail/overnight courier to Doug Dean, Director of the Colorado Public Utilities Commission, 1560 Broadway, Suite 250, Denver, CO 80202.
  - (II) If the request concerns a federal rule incorporated by reference into these rules, a review by PHMSA is required. The requestor shall submit a petition for the emergency waiver directly to the Commission using one of the methods described above and to PHMSA using any of the following methods:
    - (A) direct fax to the PHMSA Crisis Management Center at: 202-366-3768;
    - (B) direct e-mail to PHMSA at: [phmsa.pipeline-emergencyspecpermit@dot.gov](mailto:phmsa.pipeline-emergencyspecpermit@dot.gov); or
    - (C) express mail/overnight courier to the Associate Administrator for Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue, SE East Building, Washington, DC 20590.
- (f) The requestor shall include with each emergency waiver petition:
  - (I) the information required by rule 1003 paragraph (c);
  - (II) an explanation of the actual or impending emergency;
  - (III) the specific instance or illustration of the rule's application requiring modification/waiver;
  - (IV) proposed alternatives to compliance with the regulation (e.g., additional inspections and tests, shortened reassessment intervals, etc.);
  - (V) to the extent possible, as much of the information as is required in paragraph 11011(c); and
  - (VI) measures to be taken after the emergency situation or permit expires, whichever comes first, that will confirm/assure long-term operational reliability of the facility impacted by the Special Permit.

- (g) The emergency waiver is effective upon final order by the Commission or the PHMSA Administrator for Pipeline Safety, as appropriate to the review.

**11013. Inspections and Investigations.**

- (a) Upon presenting appropriate credentials, a representative of the PSP may enter upon, inspect, and examine, at reasonable times, and in a reasonable manner, the records, facilities, and properties of pipeline operators to the extent such records, facilities, and properties are relevant to determining the compliance of such operators with the requirements of these rules or Commission orders.
- (b) Prior to an inspection or investigation, the PSP Chief or assignee shall notify an operator. Except in emergency situations, the operator shall have an opportunity to respond to the notification prior to the initiation of an inspection or investigation relating to any jurisdictional pipeline facility, including the operator's right of way or easement, new and existing piping, valves, and other above ground appurtenances attached to pipes, or, upon request of PHMSA, an interstate pipeline to determine compliance with 49 U.S.C. §§ 60101 et. seq., with these rules, and with applicable Commission orders.
- (c) Inspections and investigations are necessitated by the existence of one or more of the following circumstances:
  - (I) routine scheduling by the PSP Chief, PSP Lead Engineer, or other designee;
  - (II) pipeline-related incidents and events reported to the PSP in accordance with rules 11101 through 11103;
  - (III) a complaint received from a member of the public and verified by the PSP Chief or Lead Engineer as related to a jurisdictional pipeline facility and involving a discrete and auditable matter potentially impacting public safety;
  - (IV) information obtained from a previous inspection; or
  - (V) when deemed appropriate by the Commission or PHMSA under their respective authorities.
- (d) After an inspection, the PSP Chief will pursue one of the following:
  - (I) an inspection close-out indicating that no further action will be taken on final inspection findings;
  - (II) a RFI indicating that the inspection is ongoing without final inspection findings, to be answered within the timeframe requested in the RFI, typically 30 calendar days from the operator's receipt of the RFI unless otherwise indicated and agreed to by the PSP Chief and the operator; or
  - (III) a compliance action taken on final inspection findings as described in rules 11502 and 11503.

- (e) If a representative of the PSP investigates an incident involving a pipeline facility, the PSP Chief of the Commission may request that the operator make available to the representative all records and information that directly or indirectly pertain to the incident, including integrity management plans and test results, and that the operator afford all reasonable assistance in the investigation.
- (f) To the extent necessary to carry out the responsibilities the Program Certification Obligations, the PSP may require testing of portions of pipeline facilities that have been involved in, or affected by, an incident. However, before exercising this authority and accepting responsibility, the PSP shall make every effort to negotiate a mutually acceptable plan with the owner of those facilities and, where appropriate, other local and state fire and safety authorities, PHMSA, the NTSB, and any known third parties for performing the testing.

#### **11014. Advisory Bulletins.**

PSP advisories or PHMSA advisory bulletins are periodically drafted and communicated to affected operators as a result of circumstances identified by the PSP, PHMSA, NTSB, or industry with the potential to become pipeline system safety risks. Operators should review these bulletins for relevancy to their individual pipeline system operations.

#### **11015. – 11099. [Reserved].**

### **INFORMATION REQUIRED OF OPERATORS**

#### **11100. Submission of Reports and Notices - General.**

- (a) For all annual reporting, the PSP will access the PHMSA Pipeline Data Mart beginning on March 16 of every year to confirm operator submittals. Failure to meet Annual Report submittal deadlines will result in issuance in a Warning Notice; failure to meet submittal deadlines in two successive calendar years will result in the issuance of a NPV against the operator.
- (b) For all specialized reporting, failure to meet submittal deadlines and requirements will result in issuance in a Warning Notice or a NPV against the operator.
- (c) For all electronic reporting to PHMSA, if this reporting method imposes an undue burden and hardship, an operator may submit a written request for an alternative reporting method to: Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, PHP-20, 1200 New Jersey Avenue, SE, Washington, DC 20590. The request must describe the undue burden and hardship. PHMSA will review the request and may authorize, in writing, an alternative reporting method. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202-366-8075; electronically to [informationresourcesmanaer@dot.gov](mailto:informationresourcesmanaer@dot.gov); or make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received.

#### **11101. Submission of Reports and Notices.**

- (a) Operators must submit all required reports, as applicable, within the specified deadline(s) for the following occasions requiring specialized reporting or notice. Any reporting shall be in addition to, or supplemental to, reporting required under federal law and shall not be duplicative.

(b) Incident reporting.

- (I) Written reports of all incidents required to be reported under these rules must be submitted as soon as practicable but not more than 30 days after detection of the incident.
- (II) Each operator submitting information to PHMSA via its electronic portal shall also file such information with the Commission in accordance with subparagraph 1204(a)(III) of the Commission's Rules of Practice and Procedure in the repository proceeding opened for such reporting purpose.
- (III) Each operator that submits information PHMSA via alternative methods shall file copies of this information with the Commission.
- (IV) Each operator of a distribution pipeline system, excepting MMO/LPG systems, shall submit the Incident Report (PHMSA F 7000.1) to PHMSA using its electronic portal at <https://portal.phmsa.dot.gov>.
- (V) Each operator of an MMO/LPG system shall submit a Small Operator Incident Report (PSP SOIR) to the Commission through its E-Filings System in the repository proceeding opened for such reporting purposes.
- (VI) Each operator of a transmission or Type A or Type B gathering system (i.e., excepting rural gathering), shall submit the Incident Report (PHMSA F 7100.2) to PHMSA using its electronic portal at <https://portal.phmsa.dot.gov>.
- (VII) Each operator of a LNG facility shall submit the Incident Report (PHMSA F 7100.3) to PHMSA using its electronic portal at <https://portal.phmsa.dot.gov>.
- (VIII) When additional relevant information is obtained after the report is submitted under paragraph (a) or (b) of this rule, the operator shall make supplementary reports as deemed necessary with a clear reference by date and subject to the original report. The operator shall notify the PSP Chief of all supplementary reporting.

(c) Safety-related condition (SRC) reporting.

- (I) Written reports of SRC's must be submitted in accordance with the timelines established in 49 C.F.R. Part 191, § 191.25(a).
- (II) Written reports of SRC's must be submitted with information as required in 49 C.F.R. Part 191, § 191.25(b).
- (III) Any operator filing a SRC report as required by 49 C.F.R. Part 191, § 191.23 (Reporting SRC's) and §191.25 (Filing SRC reports) with PHMSA shall also concurrently inform the PSP Chief through e-mail at [dora\\_copuc\\_pipeline\\_safety@state.co.us](mailto:dora_copuc_pipeline_safety@state.co.us) and submit the SRC report to Commission through its E-Filings System in accordance with subparagraph 1204(a)(III) of the Commission's Rules of Practice and Procedure in the repository proceeding opened for such reporting purposes no later than close of the next business day.

- (d) Pipeline damage and of locate information reporting. Each operator subject to the requirements of these rules and Colorado Revised Statutes Title 9, Article 1.5 (the “Colorado One-call Law”) shall submit the PSP Damage and Locate Report (PSP DLR) to the Commission through its E-Filings System in accordance with subparagraph 1204(a)(III) of the Commission’s Rules of Practice and Procedure in the repository proceeding opened for such reporting purposes.

**11102. Verbal Reporting of Pipeline Incidents and Events.**

- (a) Colorado pipeline incidents.
- (I) All pipeline and LNG facility operators must provide expedited reporting of a pipeline incident as soon as possible after confirmed discovery; not to exceed two hours after confirmed discovery.
  - (II) If the expedited reporting time for a pipeline incident exceeds two hours after confirmed discovery, the operator shall provide a written explanation for the time exceedance to the PSP Chief within ten business days after the incident.
  - (III) All operators must report a pipeline incident to:
    - (A) the NRC via telephone at 800-424-8802; and
    - (B) after an NRC control number is issued for the incident, to the PSP Staff via telephone at 303-894-2854.
  - (IV) A telephonic report made pursuant to this rule must include the following information:
    - (A) the NRC control number;
    - (B) the name and telephone number of the operator and the contact for more information on the incident;
    - (C) the location of the incident or event;
    - (D) the date and time of the incident or event;
    - (E) the number of fatalities and personal injuries, if any; and
    - (F) all other significant facts that are known by the person making the report that are relevant to the cause of the incident and the extent of the damage.
- (b) Colorado pipeline events.
- (I) All pipeline operators, including operators of gathering pipelines in Class 1 areas, LNG facilities/systems, and MMO/LPG systems, must provide expedited reporting of pipeline events described below as soon as possible after discovery; not to exceed two hours after confirmed discovery.



- (II) If the expedited reporting time for a pipeline event exceeds two hours after confirmed discovery, the operator shall provide a written explanation for the exceedance to the PSP Chief within ten business days after the event.
- (III) All pipeline operators must report the following pipeline events to the PSP Staff via telephone at 303-894-2854:
  - (A) an unplanned/emergency event that occurs on the pipeline system that results in the evacuation of 50 or more people from a normally occupied building or property;
  - (B) an unplanned/emergency event that occurs on the pipeline system that results in the closure of all lanes in either direction of a roadway or railroad;
  - (C) an unplanned/emergency event that occurs on the pipeline system that results in the evacuation of four or more residential structures;
  - (D) an unplanned/emergency event that occurs on the pipeline system that results in a service outage of 100 or more customers;
  - (E) an event that requires active soil vapor extraction for a period exceeding 48 hours as measured from the time the extraction device is turned on at the site until the operator determines soil vapor extraction is no longer necessary;
  - (F) a MAOP-exceedance event that requires the operator, pursuant to its procedures, to implement follow-up actions such as a leak survey; or
  - (G) an event that, in the opinion of the operator, requires courtesy notification to the PSP.

**11103. Submission of Annual Reports.**

- (a) On or before March 15 of each year, each operator shall file with the Commission an annual report for the preceding calendar year. The reports shall be filed in accordance with subparagraph 1204(a)(III) of the Commission's Rules of Practice and Procedure.
- (b) Each operator of a distribution pipeline system, excepting MMO/LPG systems, shall submit the Annual Report (PHMSA F 7100.1-1) to PHMSA using its electronic portal at <https://portal.phmsa.dot.gov>.
- (c) Each operator of an MMO/LPG system shall submit the Small Operator Annual Report (PSP SOAR) to the Commission through its E-Filings System in the repository proceeding opened for annual reports.
- (d) Each operator of a transmission or Type A or Type B gathering system (i.e., excepting rural gathering), shall submit the Annual Report (PHMSA F 7100.2-1) to PHMSA using its electronic portal at <https://portal.phmsa.dot.gov>.

- (e) Each operator of a LNG facility shall submit the Annual Report (PHMSA F 7100.3-1) to PHMSA using its electronic portal at <https://portal.phmsa.dot.gov>.

**11104. – 11199. [Reserved].**

**SAFETY STANDARDS FOR HAZARDOUS GAS PIPELINE SYSTEMS**

**11200. Standards – General.**

An operator shall comply with these rules and the minimum safety standards for the transportation of natural gas and other gas by pipeline that are incorporated by reference in rule 11008, as applicable.

**11201. Pipeline Excavation Damage Prevention.**

- (a) An operator, including operators of MMO/LPG and rural gathering pipeline systems, must be a Tier 1 Member at the UNCC/Colorado 811 if any part of the pipeline system is located in any public or railroad right-of-way.
- (b) An operator, excluding operators of MMO/LPG pipeline systems but including operators of rural gathering pipeline systems, must report underground facility damages to the UNCC/Colorado 811 in accordance with § 9-1.5-103(7), C.R.S.
- (c) Operators of MMO/LPG and rural gathering pipeline systems must install and maintain pipeline markers, labeled according to § 192.707(d), at each crossing of a public road or railroad right-of-way.
- (d) An operator, excluding operators of MMO/LPG and rural gathering pipeline systems, must have written guidelines regarding when and how civil penalties are pursued under § 9-1.5-104.5, C.R.S. against persons damaging their pipeline facilities, and when and how penalty alternatives are implemented. At a minimum, the collection of data on and subsequent analysis of the causes of excavation damages to comply with 49 C.F.R. § 192.614 (a). These guidelines must provide for:
  - (I) recording information about pipeline damages that includes identification of the responsible party and the probable cause of each excavation damage in the following categories:
    - (A) inadequate excavation practices;
    - (B) no locate requested;
    - (C) inaccurate/missing locate – Operator located; and
    - (D) inaccurate/missing located – Contractor located.
  - (II) Analysis of the information in (a) above that allows for the identification of acute risk parties that have caused multiple pipeline damages in the preceding 18 months; and

- (III) analysis of the information in (a) above that allows for the identification of chronic risk parties that have caused multiple pipeline damages over (a) time period(s) greater than 18 months.
- (e) The PSP will pursue compliance action against an operator under § 192.614(c)(5) whose excavation damages due to inaccurate or missing locates:
  - (I) were found through investigation to be contributory to a pipeline incident;
  - (II) were found through investigation to be contributory to a pipeline event that, in the opinion of the PSP, represented a major threat to public safety; or
  - (III) were found to represent an excessive risk to the operator's pipeline by the analyses required by subparagraphs 11201(d)(II) and (III).

**11202. Direct Sales Pipelines.**

Unless otherwise specified in this rule, direct sales pipelines are classified as intrastate transmission pipelines and subject to these rules and all applicable 49 C.F.R. Part 192 rules, as incorporated.

**11203. Small Operator Systems.**

- (a) General requirements.
  - (I) Unless otherwise specified in this rule, a small operator system is subject to these rules and all applicable 49 C.F.R. Part 192 rules, as incorporated.
  - (II) Unless otherwise specified in this rule, any operator of a small operator system may opt into the prescriptive distribution integrity management provisions of paragraph (h) of this rule via written request to the PSP Chief or PSP Lead Engineer.
- (b) Standards applied to de minimis gas systems.
  - (I) Unless otherwise specified in this rule, de minimis gas systems are exempt from these rules and 49 C.F.R. Part 192 rules, as incorporated.
  - (II) System expansion.
    - (A) Operators of de minimis gas systems must apply for Commission approval prior to any system expansion.
    - (B) Operators of de minimis gas systems are prohibited from expanding the system unless proper permits are issued by the appropriate plumbing inspection authority.
  - (III) Leak surveys.

- (A) De minimis gas systems must be leak surveyed with equipment using instruments and techniques suitable for detecting fugitive natural gas, or LPG in gaseous/vapor form, as applicable, once every two years.
  - (B) Records and results of all leak surveys will be kept for the life of the system.
- (IV) System repairs.
- (A) An operator of a de minimis gas system must repair all hazardous pipeline leaks immediately upon discovery.
  - (B) An operator of a de minimis gas system must repair all other pipeline system leaks within 45 days of discovery.
  - (C) All system repairs must be completed by a plumber, gas utility technician, or utility contractor qualified to install and repair underground gas systems.
  - (D) Prior to any leak repair, the operator of a de minimis gas system must acquire a plumbing permit issued by the appropriate plumbing inspection authority. If a leak has been repaired immediately due to a public safety hazard, the repair must be permitted after the fact and will be left exposed for inspection by the appropriate plumbing inspection authority or a PSP Inspector.
- (c) Standards applied to SSAG systems.
- (I) Any SSAG system is compliant with these rules if the system has been inspected and passed a system safety inspection within the last five years by one of the following means:
    - (A) inspection by the PSP;
    - (B) inspection by the Fire Department or Fire Marshall using NFPA 54 (National Fuel Gas Code), NFPA 101 (Life Safety Code), or a written equivalent standard; or
    - (C) inspection by the plumbing entity using the International Fuel Gas Code or a written equivalent standard.
  - (II) Record of the final, approved inspection of the gas system installation shall be kept for the life of the system.
  - (III) Records of all subsequent inspections shall be maintained and available for PSP inspection for a minimum of ten years from the date of inspection.
- (d) Standards applied to LPG systems.
- (I) The PSP will deem any LPG tank – CDLE OPS Inspected to be compliant with these rules, subject to the following restrictions:
    - (A) the tank has passed the CDLE OPS inspection; and

- (B) the tank has been inspected within the last five calendar years.
- (II) Leak surveys and leak pinpointing must use instruments and techniques suitable for detecting fugitive LPG in gaseous/vapor form.
- (e) Standards applied to Major MMO/LPG systems.
  - (I) Major MMO/LPG systems must acquire a PHMSA Operator Identification Number.
- (f) Standards applied to Minor MMO/LPG systems.
  - (I) Except as provided in subparagraph 11203(h)(VII), Minor MMO/LPG systems are subject to the P-DIMP of paragraph 11203(h).
- (g) Standards applied to threshold MMO/LPG systems.
  - (I) Except as provided in subparagraph 11203(h)(VII), Threshold MMO/LPG systems are subject to the P-DIMP of paragraph 11203(h).
- (h) Prescriptive distribution integrity management program (P-DIMP).
  - (I) Operators subject to this rule shall be subject to a P-DIMP consisting of an evaluation and a plan.
  - (II) Operators subject to this rule shall have a P-DIMP evaluation performed by the PSP at least once every five years; sooner when system history or PSP inspection indicates a change in any operating condition that necessitates a new P-DIMP evaluation.
  - (III) The P-DIMP shall explicitly consider, prioritize, and rank system risks based on the following:
    - (A) number of affected persons;
    - (B) physical system parameters including but not limited to:
      - (i) materials;
      - (ii) delivered system pressure, including whether the system is a low-pressure distribution system; and
      - (iii) leak and leak repair history.
    - (C) Operational system parameters including, but not limited to:
      - (i) compliance history of the current legal operator;
      - (ii) system records;

- (iii) availability of appropriate tools and equipment to operate gas pipeline system;
  - (iv) availability of trained and/or qualified personnel to operate and maintain the system during normal operations; and
  - (v) availability of trained and/or qualified personnel to operate the system during emergencies.
- (IV) All physical and operational parameters that are unknown at the time of the P-DIMP evaluation shall be considered by the PSP to pose the maximum public safety risk that is reasonably associated with the unknown parameter.
- (V) Following a completed P-DIMP evaluation, all operators of a Threshold MMO/LPG system or Minor MMO/LPG system shall be subject to P-DIMP unless the operator opts out of a P-DIMP as allowed in subparagraph 11203(h)(VII).
- (VI) The P-DIMP shall prescribe operations and maintenance activities appropriate to maximize system integrity and minimize the public safety risk posed by the operation of the system.
- (VII) P-DIMP Opt-out. An operator of a Threshold MMO/LPG system or Minor MMO/LPG system may opt-out of P-DIMP at any time by petitioning the Commission to be regulated as a Major/MMO/LPG system.

**11204. Conversion to Service.**

A pipeline previously used in service not subject to 49 C.F.R. Part 192 qualifies for service subject to 49 C.F.R. Part 192 if the operator prepares and follows a written procedure addressing the requirements of 49 C.F.R. § 192.14. The operator shall make its written procedures and applicable records available to PSP Staff upon request.

**11205. – 11299. [Reserved].**

**SAFETY STANDARDS FOR LIQUEFIED NATURAL GAS (LNG) SYSTEMS**

**11300. Standards – General.**

An operator shall comply with the safety standards for liquefied natural gas facilities that are incorporated by reference in paragraph 11008(c).

**11301. – 11399. [Reserved].**

**SAFETY STANDARDS FOR PIPELINE OPERATOR DRUG AND ALCOHOL PROGRAMS**

**11400. Standards – General.**

An operator shall comply with the standards for pipeline operator drug and alcohol programs that are incorporated by reference in paragraph 11008(d).

**11401. – 11499. [Reserved].**

**RULE VIOLATIONS, CIVIL PENALTIES, AND COMPLIANCE ACTIONS**

**11500. Violations - General.**

- (a) Violations of these rules are determined by inspections, audits, and/or testing performed under rule 11013 that indicate a compliance deficiency or deficiencies with respect to rule requirement(s).
- (b) Violations will be examined by the PSP Chief to determine impact category resulting from the violation: no immediate safety impact, incident, public endangerment, operator endangerment, or a loss/reduction of pipeline integrity.
- (c) Alleged rule violations are deemed “probable” until completion of an appropriate enforcement action, including any Commission hearing or proceeding.
- (d) The PSP Chief or PSP Staff may use the determination in paragraph (a) as a prima facie basis for opening a complaint proceeding pursuant to paragraph 1302(g) of the Commission’s Rules of Practice and Procedure.

**11501. Violations – Civil Penalties.**

- (a) This rule shall apply to violation(s) that would have otherwise been discovered by a prudent operator in the normal course of business. This is the lowest degree of culpability for which operators may be penalized and does not limit the Commission from penalizing operators for higher degrees of culpability.
- (b) An operator who violates these rules or an order of the Commission issued under these rules may be subject to civil penalties as follows:
  - (I) civil penalties shall not exceed \$100,000 per instance of violation;
  - (II) each day of a continuing violation constitutes a separate instance of violation; and
  - (III) in the case of a group or series of related violations, the aggregate amount of such penalties shall not exceed \$1,000,000.
- (c) Civil penalties – general. The PSP Chief may propose that the Commission assess civil penalties against an operator following a PSP inspection and/or investigation that has established specific pipeline safety rule violation(s) and a time-dependent or time-independent nature of the violations(s).
- (d) Civil penalties – calculation. To provide consistency and specificity, civil penalties shall be calculated through the formulaic method as follows.
  - (I) Time-dependent/history based activity violations.

- (A) Violations determined by an action or activity not performed or failure to be performed in accordance with rule or procedure:
- (i) the penalty is assessed by individual action or activity required by rule or procedure;
  - (ii) the penalty amount is calculated by the equation:

$$B \times t \times F_{ph} \times F_{hh} \times F_i,$$

where:

B = Base penalty of \$1 per day for the activity associated with the violation

t = Timeframe of non-compliance, in days

$F_{ph}$  = Pertinent/related system history factor, as determined in the Time-Dependent Violation Impact Factor Table

$F_{hh}$  = Hazardous history factor, as determined in the Time-Dependent Violation Impact Factor Table

$F_i$  = Incident history factor, as determined in the Time-Dependent Violation Impact Factor Table

- (B) Time-dependent violation impact factor table:

<b>Time-Dependent Violation Impact Factor Table</b>			
FACTOR	THRESHOLD	Factor multiplier if threshold <i>NOT</i> met	Factor multiplier if threshold met
$F_{ph}$	The violation was associated with other inspection findings that indicated related effects on pipeline system integrity (e.g., leaks, corrosion, PHMSA Advisory Bulletin, missing records, etc.)	1	5
$F_{hh}$	The violation was associated with other inspection findings that indicated related effects on public safety (e.g., hazardous leaks, safety-critical activity, safety-related condition, etc.)	1	10
$F_i$	The violation was associated with other inspection findings that indicated the violation contributed to an Incident	1	20

- (II) Time-independent/outcome-based violations.



(A) Violations determined by a failure to follow or inadequate/missing operator procedures:

- (i) the penalty is assessed by individual or group actions or activities required by rule or procedure;
- (ii) the penalty amount is calculated by the equation:

$$B \times F_{\text{impact}}, \text{ where}$$

$$B = \$5,000 \text{ base penalty per instance of violation}$$

$F_{\text{impact}}$  = Time-independent Impact Factor as determined in the Time-Independent Violation Impact Factor Table

(B) Violations determined by an unqualified worker performing operations, maintenance, or construction tasks:

- (i) the penalty is assessed per worker and specific individual qualification required by rule or procedure; and
- (ii) the penalty amount is calculated by the equation:

$$B \times F_{\text{impact}}, \text{ where}$$

$$B = \$5,000 \text{ base penalty per instance of violation}$$

$F_{\text{impact}}$  = Time-independent Impact Factor as determined in the Time-Independent Violation Impact Factor Table

(C) Rule 11201 violations:

- (i) the penalty is assessed per applicable paragraph of rule 11201;
- (ii) the penalty amount is calculated by the equation:

$$B \times F_{\text{impact}}, \text{ where:}$$

$$B = \$5,000 \text{ base penalty per instance of violation}$$

$F_{\text{impact}}$  = Time-independent Impact Factor as determined in the Time-Independent Violation Impact Factor Table

(D) Missing or incomplete records:

- (i) the penalty is assessed by grouped action or activity required by rule or procedure;

- (ii) the penalty is assessed by applicable inspection focus, i.e., district operating area, operating unit, or total operator system;
- (iii) the penalty is calculated based on the estimated volume of missing or incomplete records:
  - a. Gross Incompletion (Record incompleteness/absence  $\geq$  10 percent or complete record absence for a required code segment) = \$10,000/code/segment/calendar year;
  - b. Major Incompletion (Record incompleteness/absence  $\geq$  5 percent and  $<$  10 percent for a required code segment) = \$5,000/code/segment/calendar year;
  - c. Significant Incompletion (Record incompleteness/absence  $\geq$  2 percent and  $<$  5 percent for a required code segment) = \$2,500/code/segment/calendar year.

(E) Time-independent violation impact factor table:

<b>Time-Independent Violation Impact Factor Table</b>	
THRESHOLD	Factor multiplier if threshold met
The violation resulted in no immediate safety impact	1
The violation resulted in operator endangerment; operator property loss > \$10,000; or emergency (versus precautionary) actions by the operator necessary to protect system integrity	5
The violation resulted in public endangerment; non-operator property loss > \$10,000; or a loss of pipeline integrity	10
The violation resulted in an Incident	20

- (e) Multiple calculated penalties will be summed to compute a final civil penalty.
- (f) The PSP Chief may propose to the Commission the assessment of a revised final civil penalty lower than the summed calculated penalties based on the operator’s documented and verifiable efforts to mitigate the violations(s) and improve overall system safety and integrity.
- (g) The calculated and final civil penalty amounts shall be illustrated in the NPV to the operator.

- (h) Nothing in this rule shall prohibit the Commission from the calculation and/or assessment of a new final civil penalty during a formal hearing process.
- (i) The Commission may assess doubled or tripled civil penalties against any public utility, as provided by § 40-7-113.5(3), C.R.S., § 40-7-113.5(4), C.R.S., and this rule.
  - (I) The Commission may assess any public utility a civil penalty containing doubled penalties only if:
    - (A) the public utility has admitted liability by paying the proposed final civil penalty for, or has been adjudicated by the Commission in an administratively final written decision to be liable for, engaging in prior conduct that constituted an intentional violation of a statute in Articles 1 to 7 and 15 of Title 40, C.R.S., a Commission rule, or a Commission order;
    - (B) the conduct for which doubled civil penalties are sought violates the same statute, rule, or order as conduct for which the public utility has either admitted liability by paying the civil penalty assessment, or been adjudicated by the Commission in an administratively final written decision to be liable; and
    - (C) the conduct for which doubled civil penalties are sought occurred within one year after conduct for which the public utility has either admitted liability by paying the civil penalty assessment, or been adjudicated by the Commission in an administratively final written decision to be liable.
  - (II) The Commission may assess any public utility a civil penalty containing tripled penalties only if:
    - (A) the public utility has admitted liability by paying the proposed final civil penalty for, or has been adjudicated by the Commission in an administratively final written decision to be liable for, engaging in prior conduct that constituted two or more intentional violations of a statute in Articles 1 to 7 and 15 of Title 40, C.R.S., a Commission rule, or a Commission order;
    - (B) the conduct for which tripled civil penalties are sought violates the same statute, rule, or order as conduct for which the public utility has either admitted liability by paying the civil penalty assessment, or conduct for which the public utility has been adjudicated by the Commission in an administratively final written decision to be liable, in at least two prior instances; and
    - (C) the conduct for which tripled civil penalties are sought occurred within one year after the two most recent instances of conduct for which the public utility has either admitted liability by paying the civil penalty assessment, or been adjudicated by the Commission in an administratively final written decision to be liable.

**11502. Compliance Action - General.**

- (a) Initiation. Upon discovery of a probable violation of these rules, the PSP Chief will initiate a compliance action intended to remediate and prevent recurrence of the violation.
- (b) Intent. A compliance action is intended to minimize the realized or potential impacts of the violation on public safety and/or the integrity of the pipeline system or LNG facility and will be consistent with the intent of § 40-7-117, C.R.S. After the Commission issues a notice, an operator shall have the opportunity to respond and to cure any violation of these rules.
- (c) Structure. All compliance action notices to a pipeline operator must include:
  - (I) a statement of the law, rule(s), or order(s) that the operator is alleged to have violated; and
  - (II) a statement of the facts upon which the determination of violation is based and recommendations on actions that may be taken by the operator to remedy further noncompliance.
- (d) Service of process. Service of process shall be undertaken pursuant to rule 1205 of the Commission's Rules of Practice and Procedure and § 40-6-108, C.R.S.

**11503. Compliance Action – Warning Notice.**

In the instance of a probable violation of these rules that has no previous enforcement history and poses a low risk to public safety and/or pipeline/LNG facility integrity, as determined by current regulation, industry standard, or other relevant objective technical standard, the PSP Chief will issue a Warning Notice to an operator. The Warning Notice will advise the operator of the probable violation, require the operator to correct the probable violation or be subject to further enforcement action under these rules, and may require a formal written response from the operator on their corrective action plan so that a follow-up inspection can be scheduled.

**11504. Notice of Probable Violation (NPV).**

- (a) In the instance of a probable violation of these rules that has a previous enforcement history or poses a moderate to severe risk to public safety or pipeline or LNG facility integrity, as determined by current regulation, industry standard, or other relevant objective technical standard, the PSP Chief may issue a NPV to an operator. The NPV will advise the operator of the probable violation and include the following sections:
  - (I) a statement of inspection findings that incorporates the requirements of rule 11502, above;
  - (II) a statement of the regulatory interpretation upon which the determination of probable violation is based;
  - (III) a civil penalty calculation using rule 11501 stating separately for each probable violation the maximum penalty amount provided and a total penalty;

- (IV) the PSP Chief's civil penalty assessment evaluation consistent with § 40-7-117, C.R.S. that includes a conclusion for or against assessment of the civil penalty in whole or in part;
  - (V) a final recommended civil penalty assessment;
  - (VI) as appropriate, the NPV will offer the operator a proposed alternative enforcement in lieu of the civil penalties, in whole or in part. The proposed alternative enforcement will describe the process in sufficient detail to explain how it will provide for the improvement of public safety;
  - (VII) as appropriate, the NPV will include a compliance directive that prescribes specific actions to be taken by the operator within a specific timeframe to correct the violation; and
  - (VIII) a description of the operator's response options.
- (b) The NPV shall be filed in a new proceeding and shall serve as notice of the alleged probable violation and potential actions to be taken by the Commission.
- (c) Within 30 days after receipt of a NPV issued pursuant to the rule, an operator shall file in the proceeding its response with one of the following options.
- (I) The operator may admit the NPV through the following filings and actions:
    - (A) the operator shall pay any proposed final civil penalty in full; and
    - (B) the operator shall agree to any proposed compliance directive.
  - (II) The operator may request the Commission consider an offer in compromise to the NPV through the following filings and actions:
    - (A) the operator may request reconsideration, reissuance, or dismissal of the initial NPV through submittal of a written explanation, information, or other material in response to the allegations contained in the NPV; in objection to the proposed compliance directive; or in mitigation of the proposed final civil penalty; or
    - (B) the operator and the PSP Chief may jointly file a stipulation and settlement agreement pursuant to rule 11507, resolving the allegations in the NPV for the Commission's consideration.
  - (III) The operator may oppose the NPV, or any part thereof. The operator shall file its response opposing the allegations in the NPV in the proceeding and provide all relevant information it finds addresses the issues raised. If an operator opposes any alleged violation in the NPV, the matter shall be set for hearing. When applicable and appropriate, such appeal will stay the duration of the noncompliance for purposes of any penalty calculation contingent upon interim operator actions to cure the alleged violation(s).

- (d) If the operator fails to respond as provided in this rule within 30 days of the NPV, the NPV shall be deemed opposed by the operator and shall be set for hearing as prescribed by subparagraph (c)(III) above.

**11505. Request for Amendment (RFA).**

- (a) If an inspection, audit, or investigation reveals that an operator's plans or procedures required by these rules may be insufficient to ensure the compliant operation of a pipeline or LNG facility, the PSP Chief may issue an RFA.
- (b) The RFA shall serve as notice from the Commission of potential inadequacies and serve to facilitate and expedite necessary plan or procedure revision(s) and implementation so that pipeline operation, maintenance, training, or emergency response is not compromised. The RFA shall specify the potential inadequacies and may:
  - (I) specify a proposed timeline for revised plan implementation based on the impact to pipeline operations; and
  - (II) provide an opportunity for response.

**11506. Notice of Amendment (NOA).**

- (a) If an inspection, audit, or investigation reveals that an operator's plans or procedures required by these rules are inadequate to ensure the safe operation of a pipeline or LNG facility, the PSP Chief may issue a NOA.
- (b) The NOA shall be filed in a new proceeding and shall serve as notice from the Commission of the alleged inadequacies and to facilitate and expedite plan or procedure revision and implementation so that public safety is not compromised. The NOA shall:
  - (I) specify the alleged inadequacies and the proposed action(s) for revision of the plans and procedures;
  - (II) specify a proposed timeline for revised plan/procedure implementation based on the impact to public safety; and
  - (III) provide an opportunity for response.
- (c) Within 30 days after receipt of a NOA issued pursuant to the rule, unless a longer period is otherwise specified in the NOA or a different time period is agreed to mutually, an operator shall file in the proceeding its response with one of the following options.
  - (I) The operator may admit the NOA through the following filings and actions:
    - (A) the operator shall pay any proposed final civil penalty in full; and
    - (B) the operator shall agree to any proposed compliance directive.

- (II) The operator may request the Commission consider an offer in compromise to the NOA through the following filings and actions:
  - (A) the operator may request reconsideration and reissuance of the initial NOA through submittal of a written explanation, information, or other material in response to the allegations contained in the NOA; in objection to the proposed compliance directive; or in mitigation of the proposed final civil penalty; or
  - (B) the operator and the PSP Chief may jointly file a stipulation and settlement agreement pursuant to rule 11507, resolving the allegations in the NOA for the Commission's consideration.
- (III) The operator may oppose the NOA, or any part thereof. The operator shall file its response opposing the allegations in the NOA in the proceeding and provide all relevant information it finds addresses the issues raised. If an operator opposes any alleged violation in the NOA, the matter shall be set for hearing.
- (d) If the operator fails to respond as provided in this rule within 30 days of the NOA, the NOA shall be deemed opposed by the operator and shall be set for hearing as prescribed by subparagraph (c)(III) above.

**11507. Compliance Action – Hazardous Facilities Order (HFO).**

- (a) If an inspection, audit, investigation, or test reveals that the continued operation of a pipeline or LNG facility may pose a severe and imminent risk to public safety, as determined by current regulation, industry standard, or other relevant objective technical standard, the PSP Chief may consider the pipeline or LNG facility to be a hazardous facility and file a formal complaint with the Commission against the operator of the facility. The complaint shall allege facts sufficient to establish the existence of a hazardous facility and to support an HFO issued upon conclusion of a Commission proceeding, or, if justified, a summary HFO pursuant to paragraph (j) of this rule.
- (b) A formal complaint by PSP Staff shall be issued, and a hearing shall be conducted in accordance with the Commission's Rules of Practice and Procedure and Article 6 of Title 40, C.R.S.
- (c) Except as provided in paragraph (j) of this rule, if the Commission finds, after hearing, that a pipeline facility or a LNG facility is hazardous to life or property, the Commission shall issue an order directing the operator to take corrective action. Corrective action may include, without limitation, suspension or restriction of the use of the pipeline facility or LNG facility, physical inspection, testing, repair, or replacement.
- (d) In making a determination that a pipeline facility or a LNG facility is hazardous to life or property, the following shall be considered, as appropriate:
  - (I) the characteristics of the pipe used in the pipeline facility or the LNG facility involved, including (without limitation) its age; manufacturer; physical properties, including its resistance to corrosion and deterioration; and the method of its manufacture, construction or assembly;

- (II) the nature of the gas transported by the pipeline facility or the LNG facility, including its corrosive and deteriorative qualities; the sequence in which the gas is transported; and the pressure required for transportation of the gas;
  - (III) the characteristics of the areas in which the pipeline facility or the LNG facility is located, in particular the climatic and geotechnical or geologic conditions associated with the areas, the population, the population density, and the community growth patterns of the areas;
  - (IV) any recommendation of the NTSB issued in connection with any investigation conducted by that Board; and
  - (V) such other factors as may be relevant.
- (e) A Commission decision finding that a pipeline facility or a LNG facility is a hazardous facility shall contain a description of the corrective action required of the operator and the date by which the operator shall complete the ordered corrective action.
  - (f) The Commission shall dismiss the complaint if it determines that the pipeline facility or the LNG facility is not hazardous to life or property.
  - (g) Upon a showing that the ordered corrective action has been completed and has eliminated the condition(s) that made a pipeline facility or a LNG facility a severe and imminent risk to public safety, the Commission shall issue an order of satisfaction. Prior to issuing an order of satisfaction, the Commission may hold a hearing to determine whether the operator has completed the corrective action and whether the corrective action has eliminated the conditions(s) that made the pipeline facility or the LNG facility hazardous to life or property. The order of satisfaction shall be issued in the complaint docket in which the hazardous facilities order was entered.
  - (h) The Commission may bring a formal complaint alleging the existence of a hazardous facility supporting the issuance of an HFO and an NPV in the same proceeding, but is not required to do so.
  - (i) If the Commission determines that the delay inherent in holding a hearing may result in, and significantly increases the likelihood of, serious harm to life or property, the Commission may issue an expedited or summary HFO before holding a hearing. The provisions of paragraph (b) of this rule shall apply to a hearing held pursuant to this paragraph. The purpose of a hearing held pursuant to this paragraph is to determine whether the summary HFO should remain in effect, should be amended, or should be rescinded. The summary HFO shall include the following:
    - (I) the findings that support the determination that a summary HFO is appropriate;
    - (II) the corrective or remedial actions required of the operator; and
    - (III) a statement informing the operator of its right to a hearing, upon request, as soon as practicable after issuance of the order.



**11508. Consent Stipulations.**

- (a) If a matter has been set for hearing at any time before the issuance of a decision by the Commission, the PSP Chief and the operator may agree to dispose of the matter by a consent stipulation. The consent stipulation shall be submitted to the Commission for approval or rejection.
- (b) A consent stipulation executed under this rule shall include the following:
  - (I) an admission by the operator of facts;
  - (II) an express waiver by the operator of further procedural steps, including (without limitation) its right to a hearing; its right to seek judicial review, or otherwise to challenge or to contest the validity of the consent stipulation; and its right to seek judicial review of the Commission order accepting the consent stipulation;
  - (III) an acknowledgment by the operator that the NPV may be used to construe the terms of the consent stipulation; and
  - (IV) a statement of the actions that the operator will take and the date by which such actions shall be completed.
- (c) As appropriate, a consent stipulation executed under this rule may include a civil penalty.

**11509. Subpoenas.**

The Commission and Administrative Law Judge, or the Director may issue a subpoena in accordance with rule 1406 of the Commission's Rules of Practice and Procedure.

**11510. Injunctive Relief.**

The Commission may request that the Attorney General bring an action in an appropriate district court for injunctive or other relief as provided in Article 7 of Title 40, C.R.S. whenever the Commission is of the opinion that an operator has engaged in, is engaging in, is about to engage in, or willfully permits any act or practice that constitutes, a violation of 49 U.S.C. §§ 60101 et seq., these rules, or an order of the Commission.

**11511. – 11999. [Reserved].**

**GLOSSARY OF ACRONYMS**

C.F.R. - Code of Federal Regulations  
HFO - Hazardous Facilities Order  
LP - Liquid Petroleum  
LNG - Liquefied Natural Gas  
LPG - Liquid Petroleum Gas  
MMO - Master Meter Operator  
NFPA - National Fire Protection Association  
NOA - Notice of Amendment  
NPV - Notice of Probable Violation

NRC - National Response Center

P-DIMP - Prescriptive Distribution Integrity Management Program

PSP - Pipeline Safety Program (of the Colorado PUC)

PHMSA - U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration

RFA - Request for Amendment

RFI - Request for Information

SSAG - Single Structure Above Ground (gas pipeline system)

U.S.C. - United States Code

Decision No. C20-0917

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO**

PROCEEDING NO. 19R-0703GPS

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IN THE MATTER OF THE PROPOSED RULES REGULATING PIPELINE OPERATORS  
AND GAS PIPELINE SAFETY, 4 CODE OF COLORADO REGULATIONS 723-11.

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**COMMISSION DECISION GRANTING EXCEPTIONS TO  
DECISION NO. R20-0768 AND ADOPTING RULES**

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Mailed Date: December 28, 2020

Adopted Date: December 16, 2020

**I. BY THE COMMISSION**

**A. Statement**

1. On December 9, 2019, the Commission initiated this proceeding by issuing a Notice of Proposed Rulemaking (NOPR) to amend the Rules Regulating Pipeline Operators and Gas Pipeline Safety (Pipeline Safety Rules), moving the Pipeline Safety Rules from their present location within the Gas Utilities and Pipeline Operator Rules at 4 *Code of Colorado Regulations* (CCR), 723-4, to a new, standalone Part 11, 4 CCR 723-11 (New Pipeline Safety Rules). The matter was assigned to an Administrative Law Judge (ALJ), who issued his Recommended Decision No. R20-0768 on November 4, 2020 (Recommended Decision), after receiving significant public comment, including consideration of proposed rule revisions from stakeholder workshops and public comment hearings, and recommends the Commission adopt New Pipeline Safety Rules as attached to the Recommended Decision.

2. Through this Decision, as discussed below, we grant the narrow exceptions to the Recommended Decision filed on November 24, 2020, by Public Service Company of Colorado (Public Service). With the limited revisions proposed by Public Service included, we adopt the

New Pipeline Safety Rules that significantly alter Commission processes to better ensure public access and transparency to Pipeline Safety Program (PSP) information and processes initiated before the Commission. We commend Commission Staff and participating stakeholders that furthered this rulemaking and the Commission's continued coordination with both federal and state agencies with the singular goal of ongoing improvements in pipeline safety.

**B. Background**

3. The statutory authority for the rules proposed here is found at §§ 24-4-101 *et seq.*, 40-1-103, 40-2-108, 40-2-112, 40-2-115, 40-3-110, 40-4-109, 40-6-108, and 40-7-117, C.R.S.

4. As discussed in the NOPR, this Commission conducts its PSP activities primarily under §§ 40-1-103, 40-2-115, and 40-7-117, C.R.S. In particular, § 40-2-115, C.R.S., provides authority permitting the Commission to enter into cooperative agreements with federal agencies, directs the Commission to coordinate with state and federal agencies, and authorizes the Commission to adopt and create rules to administer and enforce the Natural Gas Pipeline Act found at 49 U.S.C. §§ 60101 *et seq.*

5. Collectively, the federal code and state statutes are provided to establish and govern regulations and standards for the safe transportation of hazardous gases by intrastate pipeline in Colorado. The PSP works in direct concert with federal regulation and administrations, and specifically the Pipeline Hazardous Materials Safety Administration (PHMSA), which includes the Office of Pipeline Safety (OPS) that regulates both hazardous gas and hazardous liquid transportation pipelines. Federal statutes and regulations, 49 *Code of Federal Regulations* (CFR) 190-99, prescribe minimum pipeline safety standards for pipeline transportation of natural gas and hazardous liquids. PHMSA-OPS oversee interstate pipelines. Under the Natural Gas Pipeline Safety Act, PHMSA provides for state oversight of intrastate regulation and enforcement. States are responsible for intrastate pipelines via interagency

agreements with PHMSA. In Colorado, the authority provided in § 40-2-115, C.R.S., enables the Commission, through its PSP, to enter into cooperative agreements with PHMSA such that it is certified to oversee intrastate pipeline transportation, as set out in statute.

6. The Commission rules regarding pipeline safety, therefore, incorporate federal standards, in addition to enabling ongoing coordination with both federal and state agencies.<sup>1</sup>

7. Current Pipeline Safety Rules were last updated in 2011, primarily revising the existing Pipeline Safety Rules to adopt amended safety rules promulgated by the U.S. Department of Transportation, 49 U.S.C. § 60105 *et seq.*, as of October 1, 2010.<sup>2</sup> Nearly a decade later, we proposed that technical updates, in addition to rule revisions for clarity and consistency, are appropriate and are included in proposed revisions. However, the primary purpose of this rulemaking is to include in rule revisions, application of more public, clear, and transparent processes concerning the Commission's PSP.

8. Traditionally, and under current Pipeline Safety Rules, the Commission authorized the PSP Chief to act on behalf of the Commission. Current rules appropriately set out verification of intrastate gas pipeline operator compliance, including enforcement and civil penalty authorities. While designation of these duties to the PSP Chief has provided efficiencies and effective regulation in the past, as discussed in the NOPR, current Commission Staff, including the PSP Chief, recognized an ongoing interest and public awareness warranting review of the processes used before this Commission. Consistent with staff suggestions, our rules aimed at adding transparency and Commissioner engagement throughout the PSP processes, including notices of proposed violations, civil penalty assessments, and reporting, in addition to adding

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<sup>1</sup> As discussed in the NOPR, authority over distinct aspects of pipeline regulations are also provided to other state agencies and commissions; *i.e.*, excavation damage regulations prescribed in § 9-1.5-101, *et seq.*, the Colorado Oil and Gas Conservation Commission under § 34-60-103, *et seq.*, and environmental regulations including those considered by the Colorado Department of Public Health and Environment. *See* Decision No. C19-0983, at ¶42.

<sup>2</sup> *See* Proceeding No. 11R-364GPS.

clarity for the public and stakeholders on any Commission actions regarding pipeline safety that are necessary.

9. Therefore, through the NOPR, we provided proposed rule revisions that significantly alter and aim to improve upon pipeline safety oversight, both substantively and administratively, at the Commission. The proposed rules also continued the Commission's ongoing commitment to added transparency, while maintaining regulatory efficiencies and continued improvement of the pipeline safety practices of the Commission's PSP. In addition, the proposed rules recognized and fostered inter-agency coordination given the necessary cooperation with PHMSA, in addition to other federal and state agencies.

10. Through its NOPR, the Commission scheduled a public comment hearing, requested comments from interested stakeholders, including in furthering the Commission's stated goals. The matter was referred this matter to an ALJ for recommended decision. From approximately late February through May of 2020, the assigned ALJ solicited comments from participants, including public comment hearings and accommodating stakeholder workshop processes led by the PSP Chief.<sup>3</sup> From this robust process, the ALJ crafted his Recommended Decision, recommending that the Commission adopt New Pipeline Safety Rules in this proceeding, which culminated from the input of dozens of stakeholder participants and furthered the Commission's interests stated in the NOPR of significantly revising and improving the PSP processes.

11. On November 24, 2020, Public Service filed exceptions to the Recommended Decision seeking minor revisions to the proposed Rule 11011, 4 CCR 723-11. Public Service

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<sup>3</sup> See Recommended Decision, at ¶¶ 3-11.

requests clarification regarding the circumstances under which PHMSA is required to review a Commission-approved rule waiver under the proposed rule.

12. Specifically, proposed Rule 11011 sets forth the requirements for requesting a non-emergency waiver or variance from any of the New Pipeline Safety Rules, including requests for waiver from the standards in 49 C.F.R. Part 192 that are incorporated by reference into the rules. As noted in the exceptions, Rule 11011 of the New Pipeline Safety Rules includes substantial changes to the process for requesting waiver. The rule outlines the process to obtain PHMSA review of any such Commission decision interpreting federal regulations, or granting such regulations that are incorporated into Commission rules. Within the updated process, decisions from an ALJ or the Commission granting a waiver from a federal regulation pursuant to Rule 11011 must be an interim decision. As the ALJ noted, including in the rule that the Commission's granting of requested waiver interpreting federal rules incorporated into the Commission's regulations aims to ensure that, during the pendency of any PHMSA review process, parties to the Commission proceedings are not required to file exceptions; rehearing, reargument, or reconsideration; or for judicial review.

13. Public Service states its appreciation for the goal of judicial efficiencies in Rule 11011 while PHMSA review is pending, but notes that no such review is necessary from PHMSA for waivers under 49 C.F.R. Part 192.1013 to alter the frequency of periodic inspections and tests on the basis of an engineering analysis and risk assessment. Public Service therefore requests that the Commission include minor revisions to Rule 11011 to recognize this exception to the general rule, and maintain that any Commission decision granting any such waiver be final (not an interim) decision.

14. No responses to Public Service’s exceptions were filed, and no other requests for modification to the New Pipeline Safety Rules were filed.

**C. Findings and Conclusions**

15. Through 49 C.F.R. part 192.1013, PHMSA review is explicitly not required. Regarding deviations from the frequency of periodic inspections and tests on the basis of an engineering analysis and risk assessment, 49 C.F.R. part 192.1013(b) clearly states:

The applicable oversight agency may accept the proposal on its own authority, with or without conditions and limitation, on a showing that the operator’s proposal, which includes the adjusted interval, will provide an equal or greater overall level of safety.

16. Based on this clear language, we agree that the proposed changes in the exceptions are reasonable. The minor requested revisions proposed by Public are appropriate, and therefore, we grant the exceptions.

17. We adopt the New Pipeline Safety Rules with the proposed revisions granted in this Decision. In doing so, we commend the PSP Chief and stakeholder participants to this proceeding that assisted in furthering the Commission’s ongoing efforts to improve upon PSP processes and rules. The resulting rules align with the intentions stated in the NOPR, and provide processes to accommodate public hearings and petition determinations, while at the same time fostering the federal and state cooperation that is required and critical to pipeline safety regulation in Colorado.

18. Public Service’s proposed changes are included in the updated New Pipeline Safety Rules adopted by, and attached to, this decision as a new Part 11, 4 CCR, 723-11. With the minor revisions included through this Decision, we adopt the Recommended Decision, including the remainder of the New Pipeline Safety Rules provided in the new 4 CCR 723-11 and revisions



to 4 CCR 723-4 that remove the Pipeline Safety Rules from the Gas Utilities and Pipeline Operator Rules.<sup>4</sup>

## II. ORDER

### A. The Commission Orders That:

1. The exceptions to Decision No. R20-0768 filed on November 24, 2020, by Public Service Company of Colorado, are granted, consistent with the discussion above.

2. The Rules Regulating Pipeline Operators and Gas Pipeline Safety, attached to this Decision are adopted, as are the revisions to the Gas Utilities and Pipeline Operator Rules.

3. The Gas Utilities and Pipeline Operator Rules at 4 *Code of Colorado Regulations* (CCR) 723-4, are attached in legislative *i.e.*, strikeout/underline format (Attachment A) and final format (Attachment B) to this Decision. The Rules Regarding Pipeline Operators and Gas Pipeline Safety, 4 CCR 723-11, are attached in final format (Attachment C) to this Decision. The attachments are also available in the Commission's E-Filing system at:

[https://www.dora.state.co.us/pls/efi/EFI.Show\\_Docket?p\\_session\\_id=&p\\_docket\\_id=19R-0703GPS](https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=19R-0703GPS)

4. Subject to filing of an application for rehearing, reargument, or reconsideration, the opinion of the Attorney General of the State of Colorado shall be obtained regarding constitutionality and legality of the rules as finally adopted. A copy of the final adopted rules shall be filed with the Office of the Secretary of State. The rules shall be effective 20 days after publication in *The Colorado Register* by the Office of the Secretary of State.

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<sup>4</sup> Attachments A and B of the Recommended Decision provide the redline legislative format and final format, respectively, of the changes removing the Pipeline Safety Rules from 4 CCR 723-4, into a new Part 11, 4 CCR 723-11, and are reattached to this decision adopting final rules.

5. The 20-day time period provided by § 40-6-114, C.R.S., to file an application for rehearing, reargument, or reconsideration shall begin on the first day after the effective date of this decision.

6. This Decision is effective upon its Mailed Date.

**B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING  
December 16, 2020.**

(S E A L)



ATTEST: A TRUE COPY

Doug Dean,  
Director

THE PUBLIC UTILITIES COMMISSION  
OF THE STATE OF COLORADO

JEFFREY P. ACKERMANN

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JOHN GAVAN

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MEGAN M. GILMAN

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Commissioners

## COLORADO DEPARTMENT OF REGULATORY AGENCIES

### Public Utilities Commission

#### 4 CODE OF COLORADO REGULATIONS (CCR) 723-4

#### PART 4

#### RULES REGULATING GAS UTILITIES ~~AND PIPELINE OPERATORS~~

##### **BASIS, PURPOSE, AND STATUTORY AUTHORITY.**

The basis and purpose of these rules is to set forth rules describing the service to be provided by jurisdictional gas utilities and master meter operators to their customers and describing the manner of regulation over jurisdictional gas utilities, master meter operators, and the services they provide. These rules address a wide variety of subject areas including, but not limited to, service interruption, meter testing and accuracy, safety, customer information, customer deposits, rate schedules and tariffs, discontinuance of service, master meter operations, transportation service, flexible regulation, procedures for administering the Low-Income Energy Assistance Act, gas service low-income program, cost allocation between regulated and unregulated operations, recovery of gas costs, appeals regarding local government land use decisions, and authority of the Commission to impose civil penalties on public utilities. The statutory authority for these rules can be found at §§ 29-20-108, 40-1-103.5, 40-2-108, ~~40-2-115~~, 40-3-102, 40-3-103, 40-3-104.3, 40-3-106, 40-3-111, 40-3-114, 40-3-101, 40-4-101, 40-4-106, 40-4-108, 40-4-109, 40-5-103, 40-7-117, 40-7-113.5, 40-7-116.5; and 40-8.7-105(5), C.R.S.

##### **GENERAL PROVISIONS**

##### **4000. Scope and Applicability.**

- (a) Absent a specific statute, rule, or Commission order which provides otherwise, all rules in this Part 4 (the 4000 series) shall apply to all jurisdictional gas utilities, gas master meter operators, ~~and gas pipeline system operators~~ and to all Commission proceedings concerning gas utilities, ~~and~~ gas master meter operators, ~~and gas pipeline safety~~.
- (b) The scope and applicability rules regarding appeals of local government land use decisions are as stated in rule 4700.
- ~~(c) The scope and applicability of rules regarding pipeline safety, which apply to pipeline operators and to those that are subject to other 4000 series rules, are as stated in rule 4900.~~

##### **4001. Definitions.**

The following definitions apply throughout this Part 4, except where a specific rule or statute provides otherwise. In addition to the definitions here, the definitions found in the Public Utilities Law and Part 1 apply to these rules. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply. In the event of a conflict between these definitions and a definition in Part 1, these definitions shall apply.

- (a) "Affiliate" of a utility means a subsidiary of a utility, a parent corporation of a utility, a joint venture organized as a separate corporation or partnership to the extent of the individual utility's involvement with the joint venture, a subsidiary of a parent corporation of a utility or where the utility or the parent corporation has a controlling interest over an entity.
- (b) "Aggregated data" means customer data, alone or in combination with non-customer data, resulting from processing (e.g., average of a group of customers) and/or a compilation of customer data of one or more customers from which and personal information has been removed.
- (c) "Applicant for service" means a person who applies for utility service and who either has taken no previous utility service from that utility or has not taken utility service from that utility within the most recent 30 days.
- (d) "Basis Point" means one-hundredth of a percentage point (100 basis points = 1 percent).
- (e) "Benefit of service" means the use of utility service by each person of legal age who resides at a premises to which service is delivered and who is not registered with the utility as the customer of record.
- (f) "Commission" means the Colorado Public Utilities Commission.
- (g) "Contracted agent" means any person that has contracted with a utility in compliance with rule 4030 to assist in the provision of regulated utility services (e.g., an affiliate or vendor).
- (h) "Cubic foot" means, as the context requires:
  - (I) At Local Pressure Conditions. For the purpose of measuring gas to a customer at local pressure conditions, a cubic foot is that amount of gas which occupies a volume of one cubic foot under the conditions existing in the customer's meter as and where installed. When gas is metered at a pressure in excess of eight inches of water column gauge pressure, a suitable correction factor shall be applied to provide for measurement of gas as if delivered and metered at a pressure of six inches of water column gauge pressure. A utility may also apply appropriate factors to correct local pressure measurement to standard conditions.
  - (II) At Standard Conditions. For all other purposes, including testing gas, a standard cubic foot is that amount of gas at standard conditions which occupies a volume of one cubic foot.
- (i) "Curtailment" means the inability of a transportation customer or a sales customer to receive gas due to a shortage of gas supply.
- (j) "Customer" means any person who is currently receiving utility service. Any person who moves within a utility's service territory and obtains utility service at a new location within 30 days shall be considered a "customer." Unless stated in a particular rule, "customer" applies to any class of customer as defined by the Commission or by utility tariff.

- (k) "Customer data" means customer specific information, excluding personal information as defined in paragraph 1004(x), that is:
  - (I) collected from the gas meter by the utility and stored in its data systems;
  - (II) combined with customer-specific energy usage information on bills issued to the customer for regulated utility service when not publicly or lawfully available to the general public; or
  - (III) about the customer's participation in regulated utility programs, such as renewable energy, demand-side management, load management, or energy efficiency programs.
- (l) "Dekatherm" (Dth) means a measurement of gas commodity heat content. One Dekatherm is the energy equivalent of 1,000,000 British Thermal Units (1 MMBtu).
- (m) "Distribution system" means the piping and associated facilities used to deliver gas to customers, excluding facilities owned by a utility that are classified on the books and records of the utility as production, storage, or transmission facilities.
- (n) "Energy assistance organization" means the nonprofit corporation established for low-income energy assistance pursuant to § 40-8.5-104, C.R.S.
- (o) "Gas" means natural gas; flammable gas; manufactured gas; petroleum or other hydrocarbon gases including propane; or any mixture of gases produced, transmitted, distributed, or furnished by any utility.
- (p) "Informal complaint" means an informal complaint as defined and discussed in the Commission's Rules Regulating Practice and Procedure.
- (q) "Interruption" means a utility's inability to provide transportation to a transportation customer, or its inability to serve a sales customer, due to constraints on the utility's pipeline system.
- (r) "Intrastate transmission pipeline" or "ITP" means generally any person that provides gas transportation service for compensation to or for another person in the State of Colorado using transmission facilities rather than distribution facilities and is exempt from FERC jurisdiction.
- (s) "Local distribution company" (LDC) means any person, other than an interstate pipeline or an intrastate transmission pipeline, engaged in the sale and distribution of gas for end-user consumption. A LDC may also perform transportation services for its end-use customers, for another LDC and/or its end-use customers, as authorized under its effective Colorado jurisdictional tariffs.
- (t) "Local government" means any Colorado county, municipality, city and county, home rule city or town, home rule city and county, or city or town operating under a territorial charter.
- (u) "Local office" means any Colorado office operated by a utility at which persons may make requests to establish or to discontinue utility service. If the utility does not operate an office in Colorado, "local office" means any office operated by a utility at which persons may make requests to establish or to discontinue utility service in Colorado.

- (v) "Main" means a distribution line that serves, or is designed to serve, as a common source of supply for more than one service lateral.
- (w) "Mcf" means 1,000 standard cubic feet.
- (x) "MMBtu" means 1,000,000 British Thermal Units, or one Dekatherm.
- (y) "Non-standard customer data" means all customer data that are not standard customer data.
- (z) "Past due" means the point at which a utility can affect a customer's account for regulated service due to non-payment of charges for regulated service.
- (aa) "Pipeline system" means the piping and associated facilities used in the transmission and/or distribution of gas.
- (bb) "Principal place of business" means the place, in or out of the State of Colorado, where the executive or managing principals who directly oversee the utility's operations in Colorado are located.
- (cc) "Property owner" means the legal owner of government record for a parcel of real property within the service territory of a utility. A utility may rely upon the records of a county clerk for the county within which a parcel of real property is located to determine ownership of government record.
- (dd) "Regulated charges" means charges billed by a utility to a customer if such charges are approved by the Commission, presented on a tariff sheet, and/or contained in a tariff of the utility.
- (ee) "Sales customer" means a person who receives sales service from a utility.
- (ff) "Sales service" means a bundled gas utility service in which the utility both purchases gas commodity for resale to the customer and delivers the gas to the customer.
- (gg) "Security" includes any stock, bond, note, or other evidence of indebtedness.
- (hh) "Service lateral" means that part of a distribution system from the utility's main to the entrance to a customer's physical location.
- (ii) "Standard conditions" means gas at a temperature of 60 degrees Fahrenheit and subject to an absolute pressure equal to 14.73 pounds per square inch absolute.
- (jj) "Standard customer data" means customer data maintained by a utility in its systems in the ordinary course of business.
- (kk) "Standby capacity" means the maximum daily volumetric amount of capacity reserved in the utility's system for use by a transportation customer, if the customer purchased optional standby service.
- (ll) "Standby supply" means the daily volumetric amount of gas reserved by a utility for the use by a transportation customer should that customer's supply fail, if the customer purchased optional standby service.

- (mm) "Third party" means a person who is not the customer, an agent of the customer who has been designated by the customer with the utility and is acting on the customer's behalf, a regulated utility serving the customer, or a contracted agent of the utility.
- (nn) "Transportation" means the exchange, forward-haul, backhaul, flow reversal, or displacement of gas between a utility and a transportation customer through a pipeline system.
- (oo) "Transportation customer" means a person who, by signing a gas transportation agreement, elects to subscribe to gas transportation service offered by a utility.
- (pp) "Unique identifier" means customer's name, mailing address, telephone number, or email address that is displayed on a bill.
- (qq) "Unregulated charges" means charges that are billed by a utility to a customer and that are not regulated or approved by the Commission, are not contained in a tariff, and are for service or merchandise not required as a condition of receiving regulated utility service.
- (rr) "Upstream pipeline" means either a natural gas pipeline or a LDC that provides gas to a LDC.
- (ss) "Utility" means a public utility as defined in § 40-1-103, C.R.S., providing sales service or transportation service (or both) in Colorado. This term includes both an ITP and a LDC.
- (tt) "Utility service" or "service" means a service offering of a utility, which service offering is regulated by the Commission.
- (uu) "Whole building data" means the sum of the monthly gas use for either all service connections at a building on a parcel of real property or all buildings on a parcel of real property.

**4002. Applications.**

- (a) Any person may seek Commission action regarding any of the following matters through the filing of an appropriate application to request a(n):
  - (I) issuance or extension of a certificate of public convenience and necessity for a franchise, as provided in rule 4100;
  - (II) issuance or extension of a certificate of public convenience and necessity for service territory, as provided in rule 4101;
  - (III) issuance of a certificate of public convenience and necessity for construction of facilities, as provided in rule 4102;
  - (IV) amendment of a certificate of public convenience and necessity to change, extend, curtail, abandon, or discontinue any service or facility, as provided in rule 4103;
  - (V) transfer a certificate of public convenience and necessity, to obtain a controlling interest in any utility, to transfer assets within the jurisdiction of the Commission or stock, or to merge a utility with another entity, as provided in rule 4104;

- (VI) approval of the issuance or assumption of any security, or to create a lien pursuant to § 40-1-104, as provided in rule 4105;
  - (VII) flexible regulatory treatment to provide service without reference to tariffs, as provided in rule 4106;
  - (VIII) amendment of a tariff on less than statutory notice, as provided in rule 4109;
  - (IX) approval of a meter sampling program, as provided in rule 4304;
  - (X) approval of a refund plan, as provided in rule 4410;
  - (XI) approval of a Low-Income Energy Assistance Plan, as provided in rule 4411;
  - (XII) approval of a cost assignment and allocation manual, as provided in rule 4503;
  - (XIII) appeal of a local government land use decision, as provided in rule 4703; or
  - (XIV) any other matter not specifically described in this rule, unless such matter is required to be submitted as a petition under rule 1304, as a motion, or as some other specific type of submittal.
- (b) In addition to the requirements of specific rules, all applications shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
- (I) the name and address of the applying utility;
  - (II) the name(s) under which the applying utility is, or will be, providing service in Colorado;
  - (III) the name, address, telephone number, and e-mail address of the applying utility's representative to whom all inquiries concerning the application should be made;
  - (IV) a statement that the applying utility agrees to answer all questions propounded by the Commission or Commission staff concerning the application;
  - (V) a statement that the applying utility shall permit the Commission or Commission staff to inspect the applying utility's books and records as part of the investigation into the application;
  - (VI) a statement that the applying utility understands that, if any portion of the application is found to be false or to contain material misrepresentations, any authorities granted pursuant to the application may be revoked upon Commission order;
  - (VII) in lieu of the separate statements required by subparagraphs (b)(IV) through (VI) of this rule, a utility may include a statement that it has read, and agrees to abide by, the provisions of subparagraphs (b)(IV) through (VI) of this rule-;



- (VIII) a statement describing the applying utility's existing operations and general service area in Colorado.
  - (IX) for applications listed in subparagraphs (a)(I), (II), (III), (V), and (VI) of this rule, the applying utility's or parent company's and consolidated subsidiaries' most recent audited balance sheet, income statement, statement of retained earnings, and statement of cash flows so long as they provide Colorado specific financial information;
  - (X) a statement indicating the town or city, and any alternative town or city, in which the applying utility prefers any hearing be held; and
  - (XI) acknowledgment that, by signing the application, the applying utility understands that:
    - (A) the filing of the application does not by itself constitute approval of the application;
    - (B) if the application is granted, the applying utility shall not commence the requested action until the applying utility complies with applicable Commission rules and with any conditions established by Commission order granting the application; and
    - (C) if a hearing is held, the applying utility shall present evidence at the hearing to establish its qualifications to undertake, and its right to undertake, the requested action.
    - (D) in lieu of the statements contained in subparagraphs (b)(XI)(A) through (C) of this rule, an applying utility may include a statement that it has read, and agrees to abide by, the provisions of subparagraphs (b)(XI)(A) through (C) of this rule.
  - (XII) An attestation which is made under penalty of perjury; which is signed by an officer, a partner, an owner, an employee of, an agent for, or an attorney for the applying utility, as appropriate, who is authorized to act on behalf of the applying utility; and which states that the contents of the application are true, accurate, and correct. The application shall contain the title and the complete address of the affiant.
- (c) In addition to the requirements of specific rules, all applications shall include the information listed in subparagraphs (a)(I) through (V) of rule 1310. Applying utilities may either include the information in the application itself, or incorporate the information by reference to the most recent miscellaneous proceeding created under rule 1310.

- (d) Customer notice. Except as required or permitted by § 40-3-104, C.R.S., if the applicant is required by statute, Commission rule, or order to provide notice to its customers of the application, the applicant shall, within seven days after filing an application with the Commission, cause to have published notice of the filing of the application in each newspaper of general circulation in the municipalities impacted by the application. The applicant shall provide proof of such customer notice within 14 days of the publication in the newspaper. Failure to provide such notice or failure to provide the Commission with proof of notice may cause the Commission to deem the application incomplete. The applicant may also be required by statute, Commission rule, or order to provide additional notice to its customers of the application by first-class mailing or by hand-delivery. Both the newspaper notice and any additional customer notice(s) shall include the following:
- (I) the title “Notice of Application by [Name of the Utility] to [Purpose of Application]”;
  - (II) state that [Name of Utility] has applied to the Colorado Public Utilities Commission for approval to [Purpose of Application]. If the utility commonly uses another name when conducting business with its customers, the “also known as” name should also be identified in the notice to customers;
  - (III) provide a brief description of the proposal and the scope of the proposal, including an explanation of the possible impact upon persons receiving the notice;
  - (IV) identify which customer class(es) will be affected and the monthly customer rate impact by customer class, if customers’ rates are affected by the application;
  - (V) identify the proposed effective date of the application;
  - (VI) identify that the application was filed on less than statutory notice or if the applicant requests an expedited Commission decision, as applicable;
  - (VII) state that the filing is available for inspection in each local office of the applicant and at the Colorado Public Utilities Commission;
  - (VIII) identify the proceeding number, if known at the time the customer notice is provided;
  - (IX) state that any person may file written comment(s) or objection(s) concerning the application with the Commission. As part of this statement, the notice shall identify both the address and e-mail address of the Commission and shall state that the Commission will consider all written comments and objections submitted prior to the evidentiary hearing on the application;
  - (X) state that if a person desires to participate as a party in any proceeding before the Commission regarding the filing, such person shall file an intervention in accordance with the rule 1401 of the Commission’s Rules of Practice and Procedure or any applicable Commission order;

- (XI) state that the Commission may hold a public hearing in addition to an evidentiary hearing on the application and that if such a hearing is held members of the public may attend and make statements even if they did not file comments, objections or an intervention. State that if the application is uncontested or unopposed, the Commission may determine the matter without a hearing and without further notice; and
- (XII) state that any person desiring information regarding if and when hearings may be held shall submit a written request to the Commission or, alternatively, shall contact the External Affairs section of the Commission at its local or toll-free phone number. Such statement shall also identify both the local and toll-free phone numbers of the Commission's External Affairs section.

**4003. [Reserved].**

**4004. Disputes and Informal Complaints.**

- (a) For purposes of this rule, "dispute" means a concern, difficulty, or problem which needs resolution and which a customer or a person applying for service brings directly to the attention of the utility without the involvement of the Commission or Commission staff.
- (b) A dispute may be initiated orally or in writing. Using the procedures found in rule 1301, a utility shall conduct a full and prompt investigation of all disputes concerning utility service.
- (c) In accordance with the procedures in rule 1301, a utility shall conduct a full and prompt investigation of all informal complaints concerning utility service.
- (d) A utility shall comply with all rules regarding the timelines for responding to informal complaints.
- (e) If a current customer, or an applicant for service that is not a current customer, is dissatisfied with the utility's proposed adjustment or disposition of a dispute, the utility shall inform the person, customer or applicant for service of the right to make an informal complaint to the External Affairs section of the Commission and shall provide to the person, customer or applicant for service the address and toll free number of the Commission's External Affairs section.
- (f) A utility shall keep a record of each informal complaint and of each dispute. The record shall show the name and address of the initiating customer or person applying for service, the date and character of the issue, and the adjustment or disposition made. This record shall be open at all times to inspection by the person who initiated the informal complaint or dispute, by the Commission, and by Commission staff.

**4005. Records.**

- (a) Except as a specific rule may require, every utility shall maintain, for a period of not less than three years, and shall make available for inspection at its principal place of business during regular business hours, the following:
  - (I) records concerning disputes, which records are created pursuant to rule 4004;

- (II) complete records of tests to determine the heating value of gas, which records are created pursuant to rule 4202;
  - (III) records concerning interruptions and curtailments of service, which records are created pursuant to rule 4203;
  - (IV) transportation request logs, which records are created pursuant to paragraph 4205(e);
  - (V) notices of rejected transportation requests, which records are created pursuant to paragraph 4206(c);(VI) transportation agreements created pursuant to rule 4206;
  - (VII) all distribution pressure records, and all records or charts made with respect to rule 4208, appropriately annotated;
  - (VIII) meter calibration records created pursuant to under rule 4303;
  - (IX) records concerning meters, which records are created pursuant to rules 4305 and 4306;
  - (X) customer billing records, which records are created pursuant to paragraph 4401(a);
  - (XI) customer deposit records, which records are created pursuant to rule 4403;
  - (XII) records and supporting documentation concerning its cost assignment and allocation manual and fully-distributed cost study pursuant to paragraphs 4503(g) and 4504(e), for so long as the manual and study are in effect or are the subject of a complaint or a proceeding before the Commission;
  - (XIII) the total gas transported under each transportation service in Mcf or MMBtu and the associated total revenue;
  - (XIV) records concerning demand side management, pursuant to rules 4750 through 4760; and
  - (XV) as applicable, the records and documents required to be created pursuant to rules 4910 through 4920.
- (b) A utility shall maintain at each of its local offices and at its principal place of business all tariffs filed with the Commission and applying to Colorado rate areas. If the utility maintains a website, it shall also maintain its current and complete tariffs on its website.
- (c) A utility shall maintain its books of account and records in accordance with the provisions of 18 C.F.R. Part 201, the Uniform System of Accounts. A utility shall maintain its books of accounts and records separately and apart from those of its affiliates.
- (d) A utility shall preserve its records in accordance with the provisions of 18 C.F.R. Part 225, the Preservation of Records of Public Utilities and Licensees.

**4006. Reports.**

- (a) On or before April 30th of each year, a utility shall file with the Commission an annual report for the preceding calendar year. The utility shall submit the annual report on forms prescribed by the Commission; shall properly complete the forms; shall ensure the forms are verified and signed by a person authorized to act on behalf of the utility; and shall file in accordance with subparagraph 1204(a)(III) of the Commission's Rules of Practice and Procedure. If the Commission grants the utility an extension of time to file the annual report, the utility nevertheless shall file with the Commission, on or before April 30, the utility's total gross operating revenue from intrastate utility business transacted in Colorado for the preceding calendar year.
- (b) If a certified public accountant prepares an annual report for a utility, the utility shall file, within 30 days after the report is final, either two paper copies of the report with the Commission or an electronic copy through the Commission's E-Filing System.
- (c) On an annual basis, a utility shall file a report stating the average time taken for service personnel to respond to gas odor calls from customers for the following:
  - (I) the entire area served by the utility within Colorado; and
  - (II) each division of the utility assigned to serve a region or portion of the utility's entire service area.

**4007. [Reserved]**

**4008. Incorporation by Reference.**

- (a) The Commission incorporates by reference 18 C.F.R. Part 201 (as published on April 1, 2012) regarding the Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act. No later amendments to or editions of 18 C.F.R. Part 201 are incorporated into these rules.
- (b) The Commission incorporates by reference 18 C.F.R. Part 225 (as published on April 1, 2012) regarding the Preservation of Records of Natural Gas Companies. No later amendments to or editions of 18 C.F.R. Part 225 are incorporated into these rules.
- (c) Any material incorporated by reference in this Part 4 may be examined at the offices of the Commission, 1560 Broadway, Suite 250, Denver, Colorado 80202, during normal business hours, Monday through Friday, except when such days are state holidays. . Incorporated standards shall be available electronically and provided in certified copies, at cost, upon request. Restrictions on the provision of physical copies due to copyright protections may apply. The Director or the Director's designee will provide information regarding how the incorporated standards may be examined at any state public depository library. The standards and regulations are also available from the agency, organization or association originally issuing the code, standard, guideline or rule as follows: Code of Federal Regulations: [www.govinfo.gov/help/cfr](http://www.govinfo.gov/help/cfr).

## **CIVIL PENALTIES**

### **4009. Definitions.**

The following definitions apply to rules 4009, 4010, and 4976, unless a specific statute or rule provides otherwise. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- (a) “Civil penalty” means any monetary penalty levied against a public utility because of intentional violations of statutes in Articles 1 to 7 and 15 of Title 40, C.R.S., Commission rules, or Commission orders.
- (b) “Civil penalty assessment” means the act by the Commission of imposing a civil penalty against a public utility after the public utility has admitted liability or has been adjudicated by the Commission to be liable for intentional violations of statutes in Articles 1 to 7 and 15 of Title 40, C.R.S., Commission rules, or Commission orders.
- (c) “Civil penalty assessment notice” means the written document by which a public utility is given notice of an alleged intentional violation of statutes in Articles 1 to 7 and 15 of Title 40, C.R.S., Commission rules, or Commission orders and of a proposed civil penalty.
- (d) “Intentional violation.” A person acts “intentionally” or “with intent” when his conscious objective is to cause the specific result proscribed by the statute, rule, or order defining the violation.

### **4010. Regulated Gas Utility Violations, Civil Enforcement, and Enhancement of Civil Penalties.**

- (a) The Commission may impose a civil penalty in accordance with the requirements and procedures contained in § 40-7-113.5, C.R.S., § 40-7-116.5, C.R.S., and paragraph 1302(b), 4 Code of Colorado Regulations 723-1, for intentional violations of statutes in Articles 1 to 7 and 15 of Title 40, C.R.S., Commission rules, or Commission orders as specified in §§ 40-7-113.5 and 40-7-116.5, C.R.S., and in these rules.
- (b) The Director of the Commission or his or her designee shall have the authority to issue civil penalty assessments for the violations enumerated in § 40-7-113.5, C.R.S., subject to hearing before the Commission. When a public utility is cited for an alleged intentional violation, the public utility shall be given notice of the alleged violation in the form of a civil penalty assessment notice.
- (c) The public utility cited for an alleged intentional violation may either admit liability for the violation pursuant to § 40-7-116.5(1)(c) or the public utility may contest the alleged violation pursuant to § 40-7-116.5(1)(d), C.R.S. At any hearing contesting an alleged violation, trial staff shall have the burden of demonstrating a violation by a preponderance of the evidence.
- (d) In any written decision entered by the Commission pursuant to § 40-6-109, C.R.S., adjudicating a public utility liable for an intentional violation of a statute in Articles 1 to 7 and 15 of Title 40, C.R.S., a Commission rule, or a Commission order, the Commission may impose a civil penalty of not more than two thousand dollars, pursuant to § 40-7-113.5(1), C.R.S. In imposing any civil penalty pursuant to § 40-7-113.5(1), C.R.S., the Commission shall consider the factors set forth in Rule 1302(b).

- (e) The Commission may assess doubled or tripled civil penalties against any public utility, as provided by § 40-7-113.5(3), C.R.S., § 40-7-113.5(4), C.R.S., and this rule.
- (f) The Commission may assess any public utility a civil penalty containing doubled penalties only if:
  - (I) the public utility has admitted liability by paying the civil penalty assessment for, or has been adjudicated by the Commission in an administratively final written decision to be liable for, engaging in prior conduct that constituted an intentional violation of a statute in Articles 1 to 7 and 15 of Title 40, C.R.S., a Commission rule, or a Commission order;
  - (II) the conduct for which doubled civil penalties are sought violates the same statute, rule, or order as conduct for which the public utility has admitted liability by paying the civil penalty assessment, or conduct for which the public utility has been adjudicated by the Commission in an administratively final written decision to be liable; and
  - (III) the conduct for which doubled civil penalties are sought occurred within one year after conduct for which the public utility has admitted liability by paying the civil penalty assessment, or conduct for which the public utility has been adjudicated by the Commission in an administratively final written decision to be liable
- (g) The Commission may assess any public utility a civil penalty containing tripled penalties only if:
  - (I) the public utility has admitted liability by paying the civil penalty assessment for, or has been adjudicated by the Commission in an administratively final written decision to be liable for, engaging in prior conduct that constituted two or more prior intentional violations of a statute in Articles 1 to 7 and 15 of Title 40, C.R.S., a Commission rule, or a Commission order;
  - (II) the conduct for which tripled civil penalties are sought violates the same statute, rule, or order as conduct for which the public utility has either admitted liability by paying the civil penalty assessment or been adjudicated by the Commission in an administratively final written decision to be liable, in at least two prior instances; and
  - (III) the conduct for which tripled civil penalties are sought occurred within one year after the two most recent prior instances of conduct for which the public utility has either admitted liability by paying the civil penalty assessment, or been adjudicated by the Commission in an administratively final written decision to be liable.
- (h) When more than two instances of prior conduct exist, the Commission shall only consider those instances occurring within one year prior to the date of such alleged conduct for which tripled civil penalties are sought.
- (i) Nothing in this rule shall preclude the assessment of tripled penalties when doubled and tripled penalties are sought in the same civil penalty assessment notice.
- (j) The Commission shall not issue a decision on doubled or tripled penalties until after the effective date of the administratively final Commission decision upon which the single civil penalty was based.

- (k) The civil penalty assessment notice shall contain the maximum penalty amount provided by rule for each individual violation noted, with a separate provision for a reduced penalty of 50 percent of the penalty amount sought if paid within ten days of the public utility's receipt of the civil penalty assessment notice.
- (l) The civil penalty assessment notice shall contain the maximum amount of the penalty surcharge pursuant to § 24-34-108(2), C.R.S., if any.
- (m) A penalty surcharge referred to in paragraph (l) of this rule shall be equal to the percentage set by the Department of Regulatory Agencies on an annual basis. The surcharge shall not be included in the calculation of the statutory limits set in § 40-7-113.5(5), C.R.S.
- (n) Nothing in these rules shall affect the Commission's ability to pursue other remedies in lieu of issuing civil penalties.

**4011. – 4024. [Reserved].**

## **CUSTOMER DATA ACCESS AND PRIVACY**

### **4025. Scope and Applicability.**

- (a) The basis and purpose of these rules is to describe the protection of and limited access to customer data for gas utilities over which the Commission has jurisdiction. These rules are applicable to all utilities except for certain provisions as defined in the rule.
- (b) For the purpose of the Customer Data Access and Privacy Rules, gas utilities are classed into three tiers: a Tier I utility serves more than 150,000 gas customers; a Tier II utility serves between 50,000 and 150,000 gas customers. A Tier III utility serves fewer than 50,000 gas customers.
- (c) No Tier III utility is required to:
  - (I) include in its tariffs a description of standard and non-standard customer data that the utility is able to provide to the customer or to any third party recipient (see paragraph 4027(c));
  - (II) provide customer notice each year regarding customer data (see rule 4028);
  - (III) make customer consent forms for the disclosure of customer data available to customers or third parties (see rule 4029);
  - (IV) disclose aggregated data (see rule 4033); or
  - (V) provide a community energy report (see rule 4035).



However, a Tier III utility may include a description of standard and non-standard customer data that the utility is able to provide to the customer or to any third-party recipient in its tariffs (in accordance with paragraph 4027(c)). Commencing upon the effective date of such description, the Tier III utility shall be deemed to be a Tier II utility for purposes of these Customer Data Access and Privacy Rules for so long as such tariff provisions remain in effect.

**4026. Customer Data.**

- (a) A utility shall maintain standard customer data sufficient to allow a customer to understand his or her energy usage at a level of detail commensurate with the metering technology used to serve the customer.

**4027. Privacy, Access, and Disclosure.**

- (a) A utility shall protect customer data in the utility's possession or control to maintain the privacy of customers, while providing reasonable access to that data. A utility is only authorized to use customer data to provide regulated utility service in the ordinary course of business.
- (b) A utility shall not disclose customer data unless such disclosure conforms to these rules, except as required by law or to comply with Commission rule. Illustratively, this includes responses to requests of the Commission, warrants, subpoenas, court orders, or as authorized by § 16-15.5-102, C.R.S.
- (c) A utility shall include in its tariffs a description of customer data that the utility is able to provide to the customer or to any third party recipient to whom the customer has authorized disclosure of the customer's data within the utility's technological and data capabilities. At a minimum, the utility's tariff must provide the following:
  - (I) a description of standard customer data and non-standard customer data and the frequency of customer data updates that will be available (annual, monthly, daily, etc.);
  - (II) the method and frequency of customer data transmittal and access available (electronic, paper, etc.) as well as the security protections or requirements for such transmittal;
  - (III) a timeframe for processing requests;
  - (IV) any rate associated with processing a request for non-standard customer data; and
  - (V) any charges associated with obtaining non-standard customer data.
- (d) As part of basic utility service, a utility shall provide access to the customer's standard customer data in electronic machine-readable form, without additional charge, to the customer or to any third party recipient to whom the customer has authorized disclosure of the customer's customer data. Such access shall conform to nationally recognized open standards and best practices. The utility shall provide access in a manner that ensures adequate protections for the utility's system security and the continued privacy of the customer data during transmission.
- (e) Nothing in these rules shall limit a customer's right to provide his or her customer data to anyone.

- (f) A utility and each of its directors, officers and employees that discloses customer data pursuant to a customer's authorization in accordance with these data privacy rules shall not be liable or responsible for any claims for loss or damages resulting from the utility's disclosure of customer data.

**4028. Customer Notice.**

- (a) A utility shall provide each year to its customers a written notice complying with this rule. The utility shall conspicuously post on its website notice of its privacy and security policies governing access to and disclosure of customer data and aggregated data to third-parties. This notice shall:
- (I) explain what is available to customers, as standard and/or non-standard customer data (e.g., daily versus hourly data);
  - (II) describe the frequency that the utility can provide customer data based on a request for standard data (e.g., on a weekly or monthly basis);
  - (III) advise customers that their customer data may provide insight into their activities within the premises receiving service;
  - (IV) inform customers that the privacy and security of their customer data will be protected by the utility while in its possession;
  - (V) explain that customers can access their standard customer data, as identified by the utility's tariff, without additional charge;
  - (VI) advise customers that their customer data will not be disclosed to third parties, except:
    - (A) as necessary to provide regulated utility services to the customers;
    - (B) as otherwise permitted or required by law or Commission rule; or
    - (C) pursuant to the authorization given by the customer in accordance with these rules.
  - (VII) describe the utility's policies regarding how a customer can authorize access and disclosure of their customer data to third-parties. With regard to such third party data disclosure, the notice shall:
    - (A) inform customers that declining a request for disclosure of customer data to a third party will not affect the provision of utility service that the customer receives from the utility; and
    - (B) explain that any customer consent for access to, disclosure of, or use of a customer's customer data by a third party may be terminated or limited by the customer of record at any time and inform the customers of the process for doing so.

- (VIII) explain that aggregated data does not contain customer identifying information and inform customers that customer data may be used to create aggregated data that will not contain customer identifying information;
- (IX) explain that the utility may provide aggregated data to third-parties, subject to its obligation under paragraph 4033(a);
- (X) be viewable on-line and printed in ten point or larger font;
- (XI) be sent either separately or included as an insert in a regular monthly bill, or, for those customers who have consented to receive e-bills, such notice may be sent electronically separately from an e-bill, conspicuously marked and stating clearly that important information on the utility's privacy practices is contained therein;
- (XII) be available in English and Spanish. The customer notice may also be translated to a language other than English or Spanish by a third party or the utility. Forms translated to other languages in accordance with this rule must be accepted by utilities, and may be relied upon, after the English version of the form, the translated version of the form, and an affidavit attesting to the accurate and complete translation from the English version of the form, have been provided to the Commission and the utility possessing the data. Such affidavit must be executed by an interpreter on the active roster of interpreters maintained by the Office of Language Access of the Colorado Judicial Branch. If the utility incurs a cost for translation made at the request of a third party, it may charge the requestor for such cost and may include a reasonable administrative fee in addition to the translation cost; and
- (XIII) provide a customer service phone number and web address where customers can direct additional questions or obtain additional information regarding their customer data, the disclosure of customer data or aggregated data, or the utility's privacy policies and procedures with respect to customer data or aggregated data.

**4029. Customer Consent Form for the Disclosure of their Customer Data to Third Party Recipients by a Utility.**

- (a) A utility shall make available to any third party a consent form for the disclosure of customer data that is maintained by the Commission and available from the Commission's website. The form shall be available electronically from the utility. The consent form shall be provided in a non-electronic format by a utility upon request from a customer or third party.
- (b) In addition to the Commission supplied form, a utility may create and make available a consent form that:
  - (I) includes the same information contained in the annual notice provided under subparagraphs 4028(a)(V), (VI), (VII), and (XIII);
  - (II) provides spaces for the following required information regarding the third party recipient of the customer data:

- (A) the name, including trade name if applicable, physical address, mailing address, e-mail address, and telephone number;
  - (B) the uses of the data for which the customer is allowing disclosure;
  - (C) the time period (e.g., months, years) for which data are being requested; and
  - (D) the description of the data that are being requested;
- (III) states that the consent is valid until terminated;
- (IV) states that the customer must notify the utility service provider in writing (electronically or non-electronically) to terminate the consent including appropriate utility contact information;
- (V) states any additional terms except an inducement for the customer's disclosure;
- (VI) be viewable on-line and printed in ten point or larger font; and
- (VII) provides notice to the customer that the utility shall not be responsible for monitoring or taking any steps to ensure that the third party to whom the data is disclosed is maintaining the confidentiality of the data or using the data as intended by the customer.
- (c) A utility may make available an electronic customer consent process for disclosure of customer data to a third party (e.g., a utility controlled web portal) that authenticates the customer identity. The contents of the electronic consent process must generally follow the format of the model consent to disclose customer data form, be clear, and include the elements to be provided pursuant to paragraph (a) of this rule. No utility is required to provide an electronic consent process in a language other than English.
- (d) A utility may make available an in-person consent process for disclosure of customer data.
- (e) A consent form may be submitted to the utility through electronic or non-electronic methods.
- (f) The scope of consent given shall be defined by the terms of the consent form, except that changes of contact names for an organization, trade name, or utility over time do not invalidate consent as to the respective organization, trade name, or utility. Because the contact named for an organization, trade name, or utility is a representative of the respective organization, trade name, or utility, consent terminates as to such contact when the relationship with the organization, trade name, or utility terminates. Modifications to the consent form over time do not invalidate previous consent. Consent need not be provided on a new form so long as the data provided remains within the scope of consent.
- (g) Customer consent forms shall be available in English and Spanish. Customer consent forms may be translated to into languages other than English or Spanish by a third party or the utility. Forms translated to other languages in accordance with this rule must be accepted by utilities, and may be relied upon, after the English version of the form, the translated version of the form, and an affidavit attesting to the accurate and complete translation from the English version of the form, have been provided to the Commission and the utility possessing the data. Such affidavit must

be signed by an interpreter on the active roster of interpreters maintained by the Office of Language Access of the Colorado Judicial Branch. If a utility incurs a cost for a translation at the request of a third party, it may charge the requestor for such cost and may include a reasonable administrative fee in addition to the translation cost.

- (h) Any customer consent forms available from the Commission's website shall be presumed to comply with these rules.

**4030. Access to Customer Data for the Provision of Regulated Utility Service.**

- (a) A utility may disclose customer data to a contracted agent provided that the contract requires the agent to:
  - (I) implement and maintain data security procedures and practices to protect the customer data from unauthorized access, destruction, use, modification, or disclosure that are equal to or greater than the data privacy and security policies and procedures used by the utility internally to protect customer data;
  - (II) use customer data solely for the purpose of the contract and prohibits the use of customer data for a secondary commercial purpose not related to the purpose of the contract without first obtaining the customer's consent as provided for in these rules;
  - (III) return to the utility or destroy any customer data that is no longer necessary for the purpose for which it was transferred; and
  - (IV) execute a non-disclosure agreement with the utility.
- (b) The utility shall maintain records of the disclosure of customer data to contracted agents for a minimum of three years. Such records shall include all contracts with the contracted agent and executed non-disclosure agreements.

**4031. Local Government Access to Customer Data from a Utility for Audit.**

- (a) A utility may disclose customer data to a local government either with an audit required to be provided pursuant to a final Commission decision (e.g., a decision approving a franchise agreement) or as reasonably necessary for an audit conducted by a governmental entity of franchise fees paid to them by the utility, provided that:
  - (I) disclosure is not otherwise prohibited by a final Commission decision (e.g., Commission-approved franchise between the utility and the local government);
  - (II) disclosure is made to a designated auditor or auditor's office, who is either an employee or agent of the local government;
  - (III) the auditor collects and uses the customer data solely for the purpose of reviewing or conducting the audit and is prohibited from disclosing or using the customer data for a purpose not related to the audit;

- (IV) the local government implements and maintains data security procedures and practices to protect the customer data from unauthorized access, destruction, use, or modification;
  - (V) the local government destroys or returns to the utility of any customer data no longer necessary for the purpose for which it was transferred unless state law or the municipality's state-mandated retention schedule requires otherwise;
  - (VI) the local government agrees not to permit access to the data by anyone that has not agreed to abide by the terms pursuant to which the data was provided by the utility. This includes, but is not limited to, all interns, subcontractors, staff, other workforce members, and consultants;
  - (VII) the local government agrees that any recipient of the data pursuant to this rule does not obtain any right, title or interest in any of the data provided by the utility;
  - (VIII) governing law or a non-disclosure agreement executed with the utility requires that the local government, at a minimum, comply with the requirements of this rule; and
  - (IX) the data requested is for utility customers served in the boundaries of the local government.
- (b) The utility shall maintain records of all disclosures of customer data to local government requestors for a minimum of three years.
  - (c) Availability of customer data pursuant to this rule does not preclude a local government from requesting other data reports.

**4032. Third Party Access to Customer Data from a Utility.**

- (a) Except as provided in this rule, paragraph 4027(b), rule 4030, and rule 4031, a utility shall not disclose customer data to any third party unless the customer or a third party acting on behalf of a customer submits a paper or electronic signed consent to disclose customer data form that has been executed by the customer of record.
- (b) Incomplete or non-compliant consent to disclose customer data forms are not valid and shall be rejected by the utility.
- (c) The utility shall maintain records of all of the disclosures of customer data to third party requestors. Such records shall include a copy of the customer's signed consent to disclose customer data form, all identifying documentation produced by the third party requestor, the customer's agreed upon terms of use, the date(s) and frequency of disclosure, and a description of the customer data disclosed.
- (d) The utility shall maintain records of customer data disclosures for a minimum of three years and shall make the records of the disclosure of a customer's customer data available for review by the customer within five business days of receiving a paper or electronic request from the customer, or at such greater time as is mutually agreed between the utility and the customer.

**4033. Requests for Aggregated Data Reports from a Utility.**

- (a) A utility shall not disclose aggregated data unless the recipient is authorized to receive all customer data within the aggregated data, and the disclosure otherwise conforms to this rule and rules 4031, 4034, and 4035. In aggregating customer data to create an aggregated data report, a utility must ensure that the data do not include any personal information or a unique identifier.
- (b) At a minimum, a particular aggregation must contain at least fifteen customers; and, within any customer class no single customer's customer data or premise associated with a single customer's customer data may comprise 15 percent or more of the total customer data aggregated per customer class to generate the aggregated data report (the "15/15 Rule").
- (c) If an aggregated data report cannot be generated in compliance with paragraph 4033(b), the utility shall notify the requestor that the aggregated data, as requested, cannot be disclosed and identify the reason(s) the request was denied. The requestor shall be given an opportunity to revise its aggregated data request in order to address the identified reason(s). An aggregated data request may be revised by expanding the number of customers or premise accounts in the request, expanding the geographic area included in the request, combining different customer classes or rate categories, or other applicable means of aggregating.
- (d) A utility shall include in its tariffs a description of standard and non-standard aggregated data reports available from the utility to any requestor. At a minimum, the utility's tariff shall provide the following:
  - (I) a description of standard and non-standard aggregated data reports available from the utility including all available selection parameters (customer data or other data);
  - (II) the frequency of data collection (annual, monthly, daily, etc.);
  - (III) the method of transmittal available (electronic, paper, etc.) and the security protections or requirements for such transmittal;
  - (IV) the charge for providing a standard aggregated data report or the hourly charge for compiling a non-standard aggregated data report;
  - (V) the timeframe for processing requests; and
  - (VI) a request form for submitting a data request for aggregated data reports to the utility identifying any information necessary from the requestor in order for the utility to process the request.
- (e) If a utility is unable to fulfill a non-standard aggregated data report request because it does not have and/or does not elect to or cannot obtain all of the data the requestor wishes to include in the aggregated data report, then the utility may contract with a contracted agent to include the additional data and process it along with the customer data in the utility's possession, to generate a non-standard aggregated data report.

- (f) A utility and each of its directors, officers and employees that discloses aggregated data as provided in these data privacy rules shall not be liable or responsible for any claims for loss or damages resulting from the utility's disclosure of aggregated data.
- (g) A utility shall not provide aggregated customer data in response to multiple overlapping requests from or on behalf of the same requestor that have the potential to identify customer data.

**4034. Property Owner Request for Whole Building Energy Use Data from a Utility.**

- (a) If requested by a property owner or its authorized agent, a Tier I utility shall provide whole building energy use data to the property owner or its authorized agent so long as:
  - (I) the whole building energy use data contains at least four customers or tenants, which may include the property owner's own account; and no single customer's customer data, unless it is the property owner's, comprises more than 50 percent of the whole building energy use data used to generate the whole building energy use data report;
  - (II) the property owner or its authorized agent agrees to not disclose the whole building energy use data except for the purposes of building benchmarking, identifying energy efficiency projects, and energy management; and
  - (III) the property owner or its authorized agent signs a non-disclosure agreement with the utility requiring the property owner, at a minimum to:
    - (A) take appropriate administrative, technical, and physical safeguards to protect the whole building data from any unauthorized use or disclosure to protect the data from unauthorized access, destruction, use, modification, or disclosure;
    - (B) only use the whole building data only for the purposes of building benchmarking, identifying energy efficiency projects, energy management, and complying with laws or ordinances;
    - (C) agree not to attempt to determine an individual utility customer's energy use from the whole building data and not to use the information to contact the subject of the information;
    - (D) agree not to use the whole building energy use data for a secondary commercial purpose not related to the authorized purpose without first obtaining the customer's consent as provided for in these rules;
    - (E) destroy any whole building energy use data that is no longer necessary for the purpose for which it was transferred;
    - (F) agree not to permit access to the whole building data by anyone that has not agreed to abide by the terms pursuant to which the data was provided by the utility. This includes, but is not limited to, all interns, subcontractors, staff, other workforce members, and consultants; and



- (G) agree that any recipient of the whole building data pursuant to this rule does not obtain any right, title or interest in any of the data provided by the utility.
- (b) Upon request by a property owner or its authorized agent, a Tier II utility shall provide whole building energy use data upon the same conditions to the extent of, and based upon, information available in the ordinary course of business.
- (c) A utility shall provide a requested whole building energy use data report in electronic, machine readable format that conforms to nationally recognized open standards and best practices.
- (d) A utility may charge a property owner or its authorized agent for the development of a whole building energy use data report. Such rate shall be determined in a utility tariff as a non-standard aggregated data report. Alternatively, the utility need not charge the customer if the cost to charge a property owner or its authorized agent is greater than the cost to develop a whole building energy use data report.
- (e) Availability of whole building energy use data pursuant to this rule does not preclude a property owner from requesting other data reports.

**4035. Community Energy Reports.**

- (a) A Tier I utility shall generate a community energy report for each local government other than a Colorado county included in its service territory with 50,000 or more residents. A Tier I utility shall generate a community energy report for each Colorado county included in its service territory with 100,000 or more residents. Any local government with fewer than 50,000 residents and Colorado county with fewer than 100,000 residents or a minority of whom are served by a Tier I utility shall be treated as if it had 50,000 or more residents served by the Tier I upon request from the local government or county. Such requests shall be made by January 31 of the calendar year following the reporting year and shall continue in effect until such time as the request is withdrawn or cancelled by the local government. All population thresholds shall be based on the most recent population estimate from the Colorado State Demography Office and where the utility serves the majority of the population.
- (b) On or before June 1 of every year, a Tier I utility shall make publicly available for download all community energy reports generated for the prior year. Reports shall be available in an electronic machine-readable form that conforms to nationally recognized open standards and best practices.
- (c) The community energy report shall include the following information and aggregated data for the utility and its customers and specific to the local government for the prior calendar year:
  - (I) the annual dekatherms consumed by customers, provided by residential, commercial, and industrial classes;
  - (II) the average number of customers in the residential, commercial, and industrial class; and
  - (III) the total annual energy saved (in dekatherms) from energy efficiency measures installed.

- (d) A local government may submit, or have another local government submit on its behalf, a GIS data to define its jurisdictional boundaries prior to the issuance of the community energy report.
- (e) Upon request by a local government, a Tier II utility shall generate a community energy report, in accordance with this rule, consistent with the utility's meter, network, or data capabilities. Such requests shall be made by January 31 of the calendar year following the reporting year and shall continue in effect until such time as the request is withdrawn or cancelled by the local government. On or before June 1 of every year, the utility shall make publicly available for download all community energy reports generated for the prior year. Reports shall be available in an electronic machine-readable form that conforms to nationally recognized open standards and best practices.
- (f) Availability of the community energy report pursuant to this rule does not preclude a local government from requesting other data reports.

**4036.– 4099. [Reserved].**

## **OPERATING AUTHORITY**

### **4100. Certificate of Public Convenience and Necessity for a Franchise.**

- (a) A utility seeking authority to provide service pursuant to a franchise shall file an application pursuant to this rule. When a utility enters into a franchise agreement with a municipality for the first time, it shall obtain authority from the Commission pursuant to § 40-5-102, C.R.S. prior to providing service under that initial franchise agreement. A utility maintains the right and obligation to serve a municipality within its service territory after the expiration of any franchise agreement.
- (b) An application for certificate of public convenience and necessity to exercise franchise rights shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) the information required in paragraphs 4002(b) and 4002(c);
  - (II) a statement of the facts (not conclusory statements) relied upon by the applying utility to show that the public convenience and necessity require the granting of the application;
  - (III) a statement describing the franchise rights proposed to be exercised. The statement shall include a description of the type of utility service to be rendered and a description of the city or town sought to be served;
  - (IV) a certified copy of the franchise ordinance; proof of publication, adoption, and acceptance by the applying utility; a statement as to the number of customers served or to be served and the population of the city or town; and any other pertinent information;
  - (V) a statement describing in detail the extent to which the applying utility is an affiliate of any other utility which holds authority duplicating in any respect the authority sought;

- (VI) the feasibility study for areas previously not served by the applying utility, which study shall at least include estimated investment, income, and expense. An applying utility may request that its most recent audited balance sheet, income statement, statement of retained earnings, and statement of cash flows be submitted in lieu of a feasibility study; and
- (VII) a statement of the names of public utilities and other entities of like character providing similar service in or near the area sought to be served.

**4101. Certificate of Public Convenience and Necessity for Service Territory.**

- (a) A utility seeking authority to provide service in a new service territory shall file an application pursuant to this rule. A utility cannot provide service to a new geographic area without authority from the Commission, unless the utility extends its facilities and service:
  - (I) within a city and county or city or town within which the utility has lawfully commenced operations;
  - (II) into territory contiguous to the utility's facility, line, plant, or system that is not served by a public utility providing the same commodity or service; or
  - (III) within or to territory already served by the utility and the extension is necessary in the ordinary course of business.
- (b) An application for certificate of public convenience and necessity to provide service in a new territory shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) the information required in paragraphs 4002(b) and 4002(c);
  - (II) a statement of the facts (not conclusory statements) relied upon by the applying utility to show that the public convenience and necessity require the granting of the application;
  - (III) a description of the type of utility service to be rendered and a description of the area sought to be served;
  - (IV) a map showing the specific geographic area that the applying utility proposes to serve. If the applying utility intends to phase in service in the territory over time, specific areas and proposed in-service dates shall be included. The map shall describe the geographic areas in section, township, and range convention;
  - (V) a statement describing in detail the extent to which the applying utility is an affiliate of any other utility which holds authority duplicating in any respect the territory sought;
  - (VI) a statement of the names of public utilities and other entities of like character providing similar service in or near the area involved in the application;

- (VII) a feasibility study for the proposed area to be served, which shall at least include estimated investment, income, and expense. An applying utility may request that its most recent audited balance sheet, income statement, statement of retained earnings, and statement of cash flows be submitted in lieu of a feasibility study; and
- (VIII) a statement of the names of public utilities and other entities of like character providing similar service in or near the area sought to be served.

**4102. Certificate of Public Convenience and Necessity for Facilities.**

- (a) A utility seeking authority to construct and to operate a facility or an extension of a facility pursuant to § 40-5-101, C.R.S., shall file an application pursuant to this rule. The utility need not apply to the Commission for approval of construction and operation of a facility or an extension of a facility which is in the ordinary course of business. The utility shall apply to the Commission for approval of construction and operation of a facility or an extension of a facility which is not in the ordinary course of business.
- (b) An application for certificate of public convenience and necessity to construct and to operate facilities or an extension of a facility pursuant to § 40-5-101, C.R.S., shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) the information required in paragraphs 4002(b) and 4002(c);
  - (II) a statement of the facts (not conclusory statements) relied upon by the applying utility to show that the public convenience and necessity require the granting of the application or citation to any Commission decision that is relevant to the proposed facilities;
  - (III) a description of the proposed facilities to be constructed;
  - (IV) estimated cost of the proposed facilities to be constructed;
  - (V) anticipated construction start date, construction period, and in-service date;
  - (VI) a map showing the general area or actual locations where facilities will be constructed, population centers, major highways, and county and state boundaries; and
  - (VII) as applicable, information on alternatives studied, costs for those alternatives, and criteria used to rank or eliminate alternatives.

**4103. Certificate Amendments for Changes in Service, in Service Territory, or in Facilities.**

- (a) A utility seeking authority to do the following shall file an application pursuant to this rule: amend a certificate of public convenience and necessity in order to extend, to restrict, to curtail, or to abandon or to discontinue without equivalent replacement any service, service area, or facility. A utility shall not extend, restrict, curtail, or abandon or discontinue without equivalent replacement any service, service area, or facility not in the ordinary course of business without authority from the Commission.

- (b) An application to amend a certificate of public convenience and necessity in order to change, to extend, to restrict, to curtail, to abandon, or to discontinue any service, service area, or facility without equivalent replacement shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
- (I) all information required in paragraphs 4002(b) and 4002(c);
  - (II) if the application for amendment pertains to a certificate of public convenience and necessity for facilities, all of the information required in rule 4102;
  - (III) if the application for amendment pertains to a certificate of public convenience and necessity for franchise rights, all of the information required in rule 4100;
  - (IV) if the application for amendment pertains to a certificate of public convenience and necessity for service territory, all of the information required in rule 4101;
  - (V) if the application for amendment pertains to a service, the application shall include:
    - (A) the requested effective date for the extension, restriction, curtailment, or abandonment or discontinuance without equivalent replacement of the service; and
    - (B) a description of the extension, restriction, curtailment, or abandonment or discontinuance without equivalent replacement sought. This shall include maps, as applicable. This shall also include a description of the applying utility's existing operations and general service area.
- (c) Customer notice of application. In addition to complying with the notice requirements of the Commission's Rules Regulating Practice and Procedure, a utility applying to curtail, restrict, abandon or discontinue service without equivalent replacement shall prepare a written notice as provided in subparagraphs 4002(d)(I) through (XII) and shall mail or deliver the notice at least 30 days before the application's requested effective date to each of the applying utility's affected customers. The customer notice shall include a statement detailing the requested restriction, curtailment, or abandonment or discontinuance without equivalent replacement.
- (d) If no customers will be affected by the grant of the application, the notice must meet the requirements of subparagraphs 4002(d)(I) through (XII) and shall be mailed to the Board of County Commissioners of each affected county, and to the mayor of each affected city, town, or municipality.

**4104. Transfers, Controlling Interest, and Mergers.**

- (a) A utility seeking authority to do any of the following shall file an application pursuant to this rule: transfer a certificate of public convenience and necessity; transfer or obtain a controlling interest in a utility, whether the transfer of control is effected by the transfer of assets, by the transfer of stock, by merger or by other form of business combination; or transfer assets subject to the jurisdiction of the Commission outside the normal course of business. A utility cannot transfer a certificate of public convenience and necessity; transfer or obtain a controlling interest in any

utility; or transfer assets outside the normal course of business without authority from the Commission.

- (b) An application to transfer a certificate of public convenience and necessity, to transfer or obtain a controlling interest in a utility, or to transfer assets subject to the jurisdiction of the Commission shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
- (I) the information required in paragraphs 4002(b) and 4002(c), as pertinent to each party to the transaction;
  - (II) a statement showing accounting entries, under the Uniform System of Accounts, including any plant acquisition adjustment, gain, or loss proposed on the books by each party before and after the transaction which is the subject of the application;
  - (III) any agreement for merger, sales agreement, or contract of sale pertinent to the transaction which is the subject of the application;
  - (IV) all facts showing that the transaction which is the subject of the application is not contrary to the public interest;
  - (V) an evaluation of the benefits and detriments to the customers of each party and to all other persons who will be affected by the transaction which is the subject of the application; and.
  - (VI) a comparison of the kinds and costs of service rendered before and after the transaction which is the subject of the application.
- (c) An application to transfer a certificate of public convenience and necessity, an application to transfer assets subject to the jurisdiction of the Commission, or an application to transfer or obtain control of the utility may be made by joint or separate application of the transferor and the transferee.
- (d) When control of a utility is transferred to another entity, or the utility's name is changed, the utility which will afterwards operate under the certificate of public convenience and necessity shall file with the Commission a tariff adoption notice, shall post the tariff adoption notice in a prominent public place in each local office and principal place of business of the utility, and shall have the tariff adoption notice available for public inspection at each local office and principal place of business. Adoption notice forms are available from the Commission. The tariff adoption notice shall contain all of the following information:
- (I) the name, phone number, and complete address of the adopting utility;
  - (II) the name of the previous utility;
  - (III) the number of the tariff adopted and the description or title of the tariff adopted;
  - (IV) the number of the tariff after adoption and the description or title of the tariff after adoption; and

- (V) unless otherwise requested by the applying utility in its application, a statement that the adopting utility is adopting as its own all rates, rules, terms, conditions, agreements, concurrences, instruments, and all other provisions that have been filed or adopted by the previous utility.

**4105. Securities and Liens.**

- (a) Subject to the exception contained in paragraph (h) of this rule, a utility which either derives more than five percent of its consolidated gross revenues in Colorado as a public utility or derives a lesser percentage if its revenues are earned by supplying an amount of energy which equals five percent or more of Colorado's consumption shall file an application for Commission approval of any proposal to issue or to assume any security or to create a lien.
- (b) An application for the issuance or assumption of securities with a maturity of 12 months or more or to create a lien shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) all information required in paragraphs 4002(b) and 4002(c);
  - (II) the resolution of the applying utility's board of directors approving the issuance, or assumption of the securities or to create a lien, together with, as applicable and available, the proposed indenture requirements, the mortgage note, the amendment to the loan contract, and the contract for sale of securities or creation of a lien;
  - (III) a statement describing each short-term and long-term indebtedness outstanding on the date of the most recent balance sheet;
  - (IV) a statement describing the classes and amounts of capital stock authorized by the articles of incorporation and the amount by each class of capital stock outstanding on the date of the most recent balance sheet;
  - (V) a statement of capital structure showing common equity, long-term debt, preferred stock, if any, and pro forma capital structure on the date of the most recent balance sheet giving effect to the issuance of the proposed securities. Debt and equity percentages to total capitalization, actual and pro forma, shall be shown;
  - (VI) a statement of the amount and rate of dividends declared and paid, or the amount and year of capital credits assigned and capital credits refunded, during the previous four calendar years including the present year to the date of the most recent balance sheet;
  - (VII) a statement describing the type and amount of securities to be issued; the anticipated interest rate or dividend rate; the redemption or sinking fund provisions, if any; and, within ten days of their filing with the Securities and Exchange Commission, the registration statement, related forms, and preliminary prospectus filed with the Securities and Exchange Commission relating to the proposed issuance;
  - (VIII) a statement of proposed uses, including construction, to which the funds will be or have been applied and a concise statement of the need for the funds; and

- (IX) a statement of the estimated cost of financing.
- (c) For applications for the creation of a lien on the applying utility's property situated within the State of Colorado where the creation of the lien is not related to the issuance or assumption of a security, the application shall also include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
- (I) a description of the property which will be subject to the lien;
  - (II) the amount of the lien;
  - (III) the proposed use of the funds to be received from the lien;
  - (IV) the estimated cost for the creation of the lien;
  - (V) the anticipated duration of the lien;
  - (VI) the anticipated release date of the lien;
  - (VII) the retirement payment plan to release the lien;
  - (VIII) a description of how the applying utility will ensure that neither the creation of the lien nor the use of the proceeds will violate § 40-3-114, C.R.S.;
  - (IX) a statement that, for the duration of the lien, the applying utility will advise the Commission within ten days of any bankruptcy, foreclosure, or liquidation proceeding; and
  - (X) a statement that the applying utility will advise the Commission within ten days of any deviation from its lien retirement payment plan;
- (d) The Commission shall issue notice of the application, which shall set a ten-day intervention period and a hearing date.
- (e) Customer notice. Within three days after the filing of an application to issue or to assume a security, the applying utility shall publish notice of the filing of the application in a newspaper of general circulation. The notice shall include, in addition to the information required by subparagraphs 4002(d)(I) – (XII), the address of the applicant.
- (f) The applying utility shall file with the Commission the published notice and an affidavit of publication as soon as possible after the filing of the application. The Commission shall not grant the application without the notice and the affidavit of publication.
- (g) The Commission shall give priority to an application made pursuant to this rule and shall grant or deny the application within 30 days after filing, unless the Commission, for good cause shown, enters an order granting an extension and stating fully the facts necessitating the extension. The Commission shall approve or disapprove an application made pursuant to this rule by written order.



- (h) Pursuant to § 40-1-104, C.R.S., a utility may issue, renew, extend or assume liability on securities, other than stocks, with a maturity date of not more than 12 months after the date of issuance, whether secured or unsecured, without application to or order of the Commission provided that no such securities so issued shall be refunded, in whole or in part, by any issue of securities having a maturity of more than 12 months except on application to and approval of the Commission.
- (i) Any security requiring Commission approval, but issued or assumed without such approval, shall be void.

**4106. Flexible Regulation to Provide Jurisdictional Service Without Reference to Tariffs.**

- (a) A utility seeking authority to provide a jurisdictional service without reference to a tariff shall file an application pursuant to this rule. A utility cannot provide a jurisdictional service without reference to a tariff without authority from the Commission.
- (b) An application for flexible regulation to provide jurisdictional service without reference to tariffs shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) all information required in paragraphs 4002(b) and 4002(c);
  - (II) the name of the customer or potential customer;
  - (III) a description of the jurisdictional service or services which the applying utility seeks to provide to a customer or a potential customer;
  - (IV) a description of the manner in which the applying utility will provide the jurisdictional service or services if it contracts with a customer or potential customer;
  - (V) the facts (not in conclusory form) which the applying utility believes satisfy the requirements of § 40-3-104.3(1)(a), C.R.S.; and
  - (VI) a statement that the applying utility has provided, or will provide when available, the application and contract as required by paragraph 4106(c) of this rule.
- (c) The contract which is the subject of the application shall be filed when available with the Commission under seal pursuant to rules 1100 through 1102 and § 40-3-104.3(1)(b), C.R.S. The applying utility shall furnish the application and, when it is available, the contract, under seal, to the OCC. Unless the applying utility requests other treatment, the Commission and the OCC shall treat the contract as confidential. If the Commission grants a protective order preserving the confidentiality of the contents of an application, then the applying utility shall also furnish a non-confidential version of the application without the contract to any utility then providing service to the customer or potential customer.

- (d) The direct testimony and attachments to be offered at hearing shall accompany the application unless the applying utility believes that the application will be uncontested and unopposed. If an attachment is large or cumbersome, the applying utility shall file the attachment with the Commission; shall provide, for the benefit of the intervenors, the title of the attachment and a summary of the information contained in the attachment; and shall state the location (other than the Commission) at which parties may inspect the attachment.
- (e) Pre-filed testimony or attachments shall not be modified once filed unless the modification is to correct typographical errors or misstatements of fact or unless all parties to the proceeding agree to the modification. In the event a substantive modification is made without the agreement of all parties, the Commission may allow the modification only upon a showing of good cause. The Commission may consider the effect of the substantive modification as a basis for a motion to continue in order to allow the Commission staff or any other party a reasonable opportunity to investigate and, if necessary, to address the modification.
- (f) The Commission shall provide notice of the application. Any person desiring to intervene in a proceeding initiated pursuant to § 40-3-104.3, C.R.S., and this rule shall move to do so within five days of the date the Commission provides notice.
- (g) Within five days of receiving written notice of an intervention in a proceeding initiated pursuant to § 40-3-104.3, C.R.S., and this rule, the applying utility shall hand-deliver or otherwise provide to the intervenor a non-confidential version of the application and the applying utility's pre-filed testimony and attachments.
- (h) Unless the Commission orders otherwise, the applying utility shall publish notice of the application in a newspaper of general circulation within three days of the filing of the application.
- (i) In addition to the requirements of subparagraphs 4002(d)(I) – (XII), the notice provided by the applying utility shall contain the following information:
  - (I) the address of the applying utility;
  - (II) the name of the customer(s) or potential customer(s) involved;
  - (III) a statement that the identified customer(s) or potential customer(s) may have the ability to provide its/their own service or may have competitive alternatives available to it/them;
  - (IV) a general description of the jurisdictional services to be provided;
  - (V) a statement of where affected customers may call to obtain information concerning the application and;
  - (VI) a statement that anyone desiring to participate as a party must file a petition to intervene within five days from the date of Commission notice of the application and that the intervention must comport with the Commission's Rules Regulating Practice and Procedure.
- (j) Within three days of providing notice, the applying utility shall file with the Commission an affidavit showing proof of publication of notice.

- (k) On a case-by-case basis, the Commission may require the applying utility to provide additional information.
- (l) Should an application be filed which the Commission determines is not complete, the Commission or Commission staff shall notify the applying utility within seven days from the date the application is filed of the need for additional information. The applying utility may then supplement the application so that it is complete. Once the application is complete, the Commission will process the application, with all applicable timelines running from the date the application is completed.
- (m) The Commission shall issue an order approving or disapproving the application within the time permitted under § 40-3-104.3(1)(b), C.R.S.
- (n) At the time of any proceeding in which a utility's overall rate levels are determined, the Commission may require the utility to file a fully distributed cost method which segregates investments, revenues, and expenses associated with jurisdictional utility service provided pursuant to any contract approved under this rule 4106 from other regulated utility operations in order to ensure that jurisdictional utility service provided pursuant to contract is not subsidized by revenues from other regulated utility operations.
- (o) The applying utility shall provide final contract or other description of the price and terms of service as specified in § 40-3-104.3(1)(e), C.R.S.

**4107. [Reserved].**

**4108. Tariffs.**

- (a) A utility shall keep on file with the Commission the following documents pertaining to gas sales service and gas transportation service: its current Colorado tariffs, forms of contracts (including gas sales agreements), and those gas transportation service agreements which are not the same as the standard gas transportation service agreement contained in the utility's tariffs. These documents, unless filed under seal, shall be available for public inspection at the Commission and at the principal place of business of the utility.
- (b) All tariffs shall comply with rule 1210 of the Commission's Rules of Practice and Procedure.
- (c) Filing and contents of tariff.
  - (l) In addition to the requirements and contents in rule 1210, the following shall be included in a utility's tariff as applicable:
    - (A) a description of the minimum heating value for gas service as required by paragraph 4202(a);
    - (B) a description of testing methods for gas quality as required by paragraph 4202(f);
    - (C) interruption and curtailment criteria, policies, and implementation priorities, as required by rule 4203;

- (D) transportation service rates, terms, and conditions, as required by rule 4205;
- (E) the utility's transportation service request form as required by paragraph 4206(a);
- (F) information regarding the utility's meter testing equipment and facilities, scheduled meter testing, meter testing records, fees for meter testing upon request, and meter reading, as required by rules 4303, 4304, 4305, 4306, and 4309;
- (G) information regarding benefit of service transfer policies as required by paragraph 4401(c);
- (H) information regarding installment payment plans and other plans, as required by rule 4404;
- (I) information regarding collection fees or miscellaneous service charges, as required by subparagraph 4404(c)(VI) and (c)(VIII).
- (J) information regarding any after-hour restoration fees, as required by paragraph 4409(b); and
- (K) all other rules, regulations, and policies covering the relations between the customer and the utility.

**4109. New or Changed Tariffs.**

- (a) A utility shall file with the Commission any new or changed tariffs. No new or changed tariff shall be effective unless it is filed with the Commission and either is allowed to go into effect by operation of law or is approved by the Commission.
- (b) A utility shall use one of the following processes to seek to add a new tariff or to change an existing tariff:
  - (I) The utility may file the proposed tariff, including the proposed effective date, accompanied by an advice letter pursuant to rule 1210. The utility shall provide notice in accordance with rule 1206. If the Commission does not suspend the proposed tariff in accordance with rule 1305 prior to the tariff's proposed effective date, the proposed tariff shall take effect on the proposed effective date.
  - (II) The utility may file an application to implement a proposed tariff on less than 30-days' notice, accompanied by the proposed tariff, including the proposed effective date. The utility shall provide notice in accordance with rule 1207. The application shall include the information required in paragraphs 4002(b) and 4002(c); shall explain the details of the proposed tariff, including financial data if applicable; shall state the facts which are the basis for the request that the proposed tariff become effective on less than 30-days' notice; and shall identify any prior Commission action, in any proceeding, pertaining to the present or proposed tariff.

- (III) Unless the Commission orders otherwise, a utility shall be permitted to file new tariffs complying with an order of the Commission or updating adjustment clauses previously approved by the Commission on not less than two business days' notice. No additional notice beyond the tariff filing itself shall be required.

**4110. Advice Letters.**

- (a) All advice letter filings shall comply with rule 1210 of the Commission's Rules of Practice and Procedure.
- (b) In addition to the requirements and contents in rule 1210, the advice letter shall include the estimated amounts, if any, by which the utility's revenues will be affected, calculated on an annual basis.
- (c) Customer notice of advice letter. If the utility is required by statute, Commission rule or order to provide notice to its customers of the advice letter, such notice shall include the requirements of subparagraphs 4002(d)(I) – (XII).

**4111. – 4199. [Reserved]**

**FACILITIES**

**4200. Construction, Installation, Maintenance, and Operation.**

The gas plant, equipment, and facilities of a utility shall be constructed, installed, inspected, maintained, and operated in accordance with accepted engineering and gas industry practices to assure continuity of service, uniformity in the quality of service, and the safety of persons and property.

**4201. Instrumentation.**

A utility purchasing natural gas energy or receiving natural gas energy for transportation services shall install, or shall require the interconnecting pipeline to provide, such instruments or meters as may be necessary to furnish information detailing the quantity and quality of gas received into its system as necessary to maintain measurement accuracy and acceptable gas quality.

**4202. Heating Value, Purity, and Pressure.**

- (a) A utility shall establish and maintain in its tariffs a minimum heating value for its gas, expressed in British Thermal Units per standard cubic foot. The minimum heating value shall be no less than the monthly average gross heating value of gas supplied by the utility in any given service area. No deviation below this minimum shall be permitted. The utility shall determine the heating value of gas by testing gas taken from such points on the utility's system and at such test frequencies as are reasonably necessary for a proper determination. The utility shall maintain records of tests conducted to determine the heating value of gas. The results of these tests shall be stated in terms of standard conditions.
- (b) A change in minimum heating value shall require an appropriate adjustment, if any, to rates.

- (c) The utility shall insure that the gas it supplies, if from multiple sources or if the supply from a single source changes in composition, is interchangeable for safe and efficient use. The utility shall insure that gas from new supply sources or from supply sources which the gas composition has changed is interchangeable with the gas it currently supplies. The utility shall evaluate interchangeability by means of one of the following:
  - (I) use of test results which establish that the gas supplied to the end-user falls within an acceptable range and which take into account the heating value, specific gravity, and composition of the gas;
  - (II) use of actual appliances to determine acceptability; or
  - (III) use of a standard in the natural gas industry.
- (d) A utility shall promptly readjust its customers' appliances and devices as necessary to render proper service if the readjustment is required for safe and efficient use in accordance with paragraph (c) of this rule. Unless otherwise ordered by the Commission, a readjustment made pursuant to this paragraph shall be done at no charge to the customer. If a utility determines that a readjustment pursuant to this paragraph is necessary, the utility shall notify the Commission, in writing, of the readjustment and of the reason for the readjustment.
- (e) A utility whose gas delivery exceeds 20 million cubic feet per annum shall test the heating value of gas at least once each week, unless the utility purchases or receives gas on a heat value basis or unless the interconnecting pipeline provides the utility with a record of the heating value of the gas delivered and the interconnecting pipeline's tests are made at least once each week.
- (f) All gas supplied to customers shall be substantially free of impurities which may cause corrosion of facilities or which may form corrosive or harmful fumes when burned in a properly-designed and properly-adjusted burner.
- (g) A LDC shall deliver gas at a pressure of six inches water column, plus or minus two inches water column, measured at the meter outlet, unless operating conditions require a higher delivery pressure. If a higher pressure is required, the utility shall require the customer to install appropriate pressure regulating equipment in the customer's lines, if necessary.
- (h) A utility shall monitor distribution pressure as follows:
  - (I) In a distribution system serving 100 or fewer customers, the utility shall semi-annually check distribution pressures by indicating gauges at the district regulator station or other appropriate point in the distribution system.
  - (II) In distribution system serving more than 100 and fewer than 500 customers, the utility shall provide at least one recording pressure gauge or telemetering pressure device at the pressure regulating station or at some other appropriate point in the distribution system.

(III) In a distribution system serving 500 or more customers, the utility shall maintain one or more additional recording pressure gauges or telemetering pressure devices and shall make frequent 24-hour records of the gas pressure prevailing at appropriate points in the system.

(i) In its tariff, a utility shall include a description of test methods, equipment, and frequency of testing used to determine the quality and pressure of gas service furnished.

**4203. Interruptions and Curtailments of Service.**

(a) A utility shall keep a record of all interruptions and curtailments of service on its entire system or on major divisions of its system, including a statement of the time, duration, and cause of each interruption or curtailment. A utility shall also keep a record of the time of starting up or shutting down of the compressing equipment and the period of operation of all regulators used for the maintenance of constant gas pressure.

(b) In its tariff a utility shall establish specific terms and conditions for interruptions and curtailments of service. The utility shall establish, and adhere to, interruption and curtailment priorities for sales service and for transportation service by customer class. These priorities shall be consistent with the requirements of this rule.

(c) A utility shall interrupt service within each class on an equitable basis, consistent with system constraints and its tariff. A utility shall interrupt service within a locale on a fair and reasonable basis, consistent with local conditions.

(d) A utility shall not make up any shortage by using the transportation customer's supplies without the transportation customer's consent.

(e) A utility shall curtail standby supply service to transportation customers who have contracted for standby supply service in accordance with the same system of class-by-class priorities as is applicable to sales customers established by the utility's tariffs.

(f) A utility may provide, under applicable sales tariffs, available supply service to gas transportation customers who have not purchased standby supply service from the utility and are experiencing supply shortages.

**4204. [Reserved].**

**4205. Gas Transportation Service Requirements.**

(a) In its tariffs, a utility shall establish maximum rates for gas transportation service. In addition, a utility which desires price flexibility shall include its minimum rates in its tariffs. The following apply to transportation tariff rates:

(I) Maximum rates for transportation shall be based on fully allocated cost methods and shall include an allowance for return on allocated rate base equal to the last rate of return authorized by the Commission for the utility.

- (II) A utility may, at its discretion, offer natural gas transportation standby capacity service or standby supply service. A utility may require separate charges for:
  - (A) natural gas transportation standby capacity (if offered);
  - (B) standby supply (if offered);
  - (C) administration, services and facilities; and
  - (D) a utility's avoidable purchased gas commodity costs based on current market-driven gas prices.
  
- (b) In its tariffs, a utility shall establish terms and conditions for gas transportation service, including at least the following:
  - (I) all criteria for determining gas transportation capacity;
  - (II) all gas transportation costs;
  - (III) all nomination requirements;
  - (IV) all measurement and facility requirements;
  - (V) as applicable, all gas supply cost provisions;
  - (VI) all gas balancing provisions;
  - (VII) all quality of gas requirements;
  - (VIII) the utility's line extension policy;
  - (IX) the gas transportation request form required by paragraph 4206(a);
  - (X) the utility's gas transportation standard gas transportation service agreement, which shall include the statements required by paragraph 4206(d); and
  - (XI) the utility's standard agency agreement required by paragraph 4206(e).

**4206. Gas Transportation Agreements.**

- (a) When a customer requests transportation service, a utility shall provide the customer requesting transportation with the utility's gas transportation form. This form shall set out clearly the information necessary for the utility to determine whether it can provide the requested transportation.
  
- (b) In determining whether capacity is available to provide the requested transportation, a utility shall take into account all conventional methods of delivering gas through its system, including without limitation forward haul, compression, exchange, flow reversal, backhaul, and displacement. The



utility is not required to perform exchanges or displacements over segments of its system which are not physically connected.

- (c) A utility shall process, shall approve or reject, and shall provide notification of its decision with respect to a transportation request within 60 days after receiving a written request from a transportation customer. If the utility rejects the request, the utility shall provide, within three business days, written notice of its decision to the customer and shall retain a record of the rejection notice for two years. The notice shall detail the reasons for the rejection and shall explain what changes are necessary to make the request acceptable. If the request is approved, the utility shall provide, within three business days, written notification of approval to the customer.
- (d) A utility shall maintain on file with the Commission a standard gas transportation agreement. All gas transportation agreements shall contain the following provisions.
  - (I) This agreement, and all its rates, terms and conditions as set out in this agreement and as set out in the tariff provisions which are incorporated into this agreement by reference, shall at all times be subject to modification by order of the Commission upon notice and hearing and a finding of good cause therefore. In the event that any party to this agreement requests the Commission to take any action which could cause a modification in the conditions of this agreement, the party shall provide written notice to the other parties at the time of filing the request with the Commission.
  - (II) If the end-use customer uses a marketing broker for nomination, gas purchases, and balancing, the end-use customer shall provide the utility with an agency agreement.
- (e) A utility shall maintain on file with the Commission the standard agency agreement to be used when an end-use transportation customer uses a third party for any services related to nomination, gas purchases, and balancing activities.
- (f) A utility shall maintain logs showing all requests for gas transportation. The log shall contain the following information: the identity of the party making the transportation request, the date of the request, the volume requirements, duration, receipt and delivery points, type of service, and the disposition of the request. The utility shall retain these logs for two years.

**4207. Purchases Replaced by Transportation.**

- (a) Any reduction of gas purchases by a current sales customer who replaces sales purchases with transportation directly reduces a utility's obligation to provide gas to that customer on both a peak day and on an annual volume basis. If offered by the utility, a customer may retain rights to gas supplies by electing to pay for standby capacity service and standby supply service.
- (b) Any reduction of gas purchases by a current interruptible sales customer who replaces said purchases with transportation gas directly reduces the utility's obligation to provide gas supplies to that customer on an annual volume basis. At the discretion of the utility, a customer may retain rights to interruptible gas supplies by electing to pay for standby supply service.

- (c) If a sales customer converts all, or a portion, of its service to transportation and if it does not elect standby supply service, then the customer must reapply for sales service in the future if it wishes to convert the transportation portion of its service back to sales service.
- (d) The utility shall have no sales service obligation to a transportation customer who is solely responsible for procuring its own gas supply. The customer may retain rights to gas supplies by electing to pay for standby supply service.

**4208. Anticompetitive Conduct Prohibited.**

- (a) A utility shall apply all transportation rates and policies without undue discrimination or preference to its affiliates. Each contract to transport gas for a marketing or brokering affiliate of a utility shall be an arm's-length agreement containing only terms which are available to other transportation customers.
- (b) A utility is prohibited from engaging in anticompetitive conduct, discriminatory behavior, and preferential treatment in transporting gas, including (without limitation) the following:
  - (I) disclosure to a marketing or brokering affiliate of confidential information provided by nonaffiliated transportation customers;
  - (II) disclosing to any transportation customer the utility's own confidential information unless the same information is communicated contemporaneously to all current transportation customers;
  - (III) disclosing to any transportation customer of information filed with a transportation request unless the same information is communicated contemporaneously to all current transportation customers;
  - (IV) providing any false or misleading information, or failing to provide information, regarding the availability of capacity for transportation service;
  - (V) tying an agreement to release gas to an agreement by the transportation customer to obtain services from a marketing or brokering affiliate of the utility or to an offer by the utility to provide or to expedite transportation service to its affiliate for the released gas;
  - (VI) providing any false or misleading information, or failing to provide information, about gas releases;
  - (VII) failing to notify all affiliate brokers and marketers and all transportation customers of gas releases at the same time and in the same manner or otherwise allowing marketing or brokering affiliates preferential access to released gas;
  - (VIII) lending gas to a marketing or brokering affiliate to meet balancing requirements except under terms available to other transportation customers;
  - (IX) directing potential customers to the utility's own marketing or brokering affiliate, but the utility may provide a list of all registered gas marketers and brokers, including its affiliates;

- (X) charging lower rates to a transportation customer conditioned on the purchase of gas from the utility's marketing or brokering affiliate;
- (XI) conditioning the availability of transportation service upon the use of the utility's marketing or brokering affiliate;
- (XII) providing exchange or displacement services to one transportation customer without providing them to others on the same terms and conditions;
- (XIII) giving its marketing affiliate preference over nonaffiliated customers in matters relating to transportation including, but not limited to, scheduling, balancing, transportation, storage, or curtailment priority;
- (XIV) disclosing to its affiliate any information the utility received from a nonaffiliated transportation customer or potential nonaffiliated transportation customer;
- (XV) failing contemporaneously to provide identical gas transportation sales or marketing information it provides to a marketing affiliate to all potential transportation customers, affiliated and nonaffiliated, on its system; and
- (XVI) failing to make available to all similarly-situated nonaffiliated transportation customers discounts which are comparable to those made to an affiliated marketer.

**4209. [Reserved].**

**4210. Line Extension.**

- (a) A utility shall have tariffs which set out its line extension policies, procedures, and conditions.
- (b) In its tariff a LDC shall include the following provisions for gas main extensions and service lateral extensions from its distribution system:
  - (I) the terms and conditions, by customer class, under which an extension will be made;
  - (II) provisions requiring the utility to provide to a customer or to a potential customer, upon request, service lateral connection information necessary to allow the customer's or potential customer's facilities to be connected to the utility's system;
  - (III) provisions requiring the utility to exercise due diligence in providing the customer or potential customer with an estimate of the anticipated cost of a connection or extension; and
  - (IV) provisions addressing steps to ameliorate the rate and service impact upon existing customers, including stating in the tariff the procedures by which future customers would share costs incurred by the initial or existing customers served by a connection or extension (as, for example, by including the procedures by which a refund of customer connection or extension payments would be made when appropriate).

**4211. – 4299. [Reserved].**

## **METERS**

### **4300. Service Meters and Related Equipment.**

- (a) All meters used in connection with gas metered service for billing purposes shall be furnished, installed, and maintained by the utility.
- (b) All equipment, devices, or facilities (including, without limitation, service meters) furnished by the utility and which the utility maintains and renews shall remain the property of the utility and may be removed by it at any time after discontinuance of service.
- (c) Each service meter shall indicate clearly the cubic feet or other units of service for which the customer is charged for service through each meter. In cases in which the dial reading of a meter, other than an orifice or other chart type meter, must be multiplied by a constant or factor to obtain the units consumed, the factor, factors, or constant shall be clearly marked on the dial or face of the meter, if possible. In the alternative, the constant, constants, or factor, or the method of calculating the constant, constants, or factor, shall be stated clearly on a customer's bill, with step by step instructions to allow customer to convert the unit of measurement from the dial of the meter to the billing unit or billing determinant on the bill.

### **4301. Location of Service Meters.**

- (a) As of the time of installation, meters shall be located in accordance with the pertinent utility tariffs and in accordance with accepted safe practice and gas utility industry standards.
- (b) As of the time of installation, meters shall be located so as to be easily accessible for reading, testing, and servicing in accordance with accepted safe practice and in accordance with gas utility industry standards.

### **4302. Service Meter Accuracy.**

- (a) Before being installed for use by a customer, every gas service meter, whether new, repaired, or removed from service for any cause shall be in good order and, except as provided in paragraph (b) of this rule, shall be adjusted to be correct to within one percent when passing gas at 20 percent of its rated capacity at one-half inch water column differential.
- (b) New rotary displacement type gas service meters in sizes having a rated capacity of more than 5,000 cubic feet per hour at a differential not to exceed two inches water column shall be tested and calibrated at the factory in accordance with recognized and accepted practices. These meters shall also be adjusted to be correct within two percent slow and one percent fast when passing gas at ten percent of its rated capacity and shall be adjusted to be correct within one percent slow and one percent fast when passing gas at 100 percent of its rated capacity. Prior to reuse of a rotary displacement type meter that has been removed from service, the meter shall pass the same testing criteria as a new meter.

### **4303. Meter Testing Equipment and Facilities.**

- (a) A utility shall provide, or shall arrange for a qualified third party to provide, such equipment and facilities as may be necessary to make the tests and to provide the service required. Such

equipment and facilities shall be available at all reasonable times for inspection by Commission staff.

- (b) A utility having more than 200 meters in service shall maintain, or shall require the qualified third party that provides meter testing equipment and facilities to maintain, suitable gas meter testing equipment in proper adjustment so as to register the condition of meters tested within one-half of one percent. The utility shall have and shall maintain, for the testing equipment, necessary certificate(s) of calibration showing that the equipment has been tested with a standard certified by the National Institute of Standards and Technology or other laboratory of recognized standing.
- (c) In its tariff, a utility shall include a description of its meter testing equipment and of the methods employed to ascertain and to maintain accuracy of all testing equipment.
- (d) A utility shall keep records of certification and calibrations for all testing equipment required by this rule for the life of the equipment.

**4304. Scheduled Meter Testing.**

- (a) A utility shall test, or shall arrange for testing of, service meters in accordance with the schedule in this rule or in accordance with a sampling program approved by the Commission.
- (b) If it wishes to use a sampling program, a utility shall file an application to request approval of a sampling program. The application shall include:
  - (I) the information required by paragraphs 4002(b) and 4002(c);
  - (II) a description of the sampling program which the utility wishes to use. This description shall include, at a minimum the following:
    - (A) the type(s) of meters subject to the sampling plan;
    - (B) the frequency of testing;
    - (C) the procedures to be used for the sampling;
    - (D) the meter test method to be used;
    - (E) the accuracy of the testing and of the sampling plan;
    - (F) an explanation of the reason(s) for the requested sampling program; and
    - (G) an analysis which demonstrates that, with respect to assuring the accuracy of the service meters tested, the requested sampling program is at least as effective as the schedule in this rule.
- (c) Revisions to any portion of a sampling program approved pursuant to the procedure in paragraph (b) of this rule shall be accomplished by the filing of, and Commission approval of, a new application.

- (d) Every service meter shall be tested and adjusted before installation to ensure that it registers accurately and conforms with the requirements of rule 4302. In addition, every service meter shall be tested on a periodic basis, as follows:
  - (I) diaphragm type gas service meter in sizes having rated capacity of 800 cubic feet or less per hour at one-half inch water column differential, every six years;
  - (II) diaphragm type gas service meter in sizes having a rated capacity of more than 800 cubic feet per hour at one-half inch water column differential, every five years;
  - (III) rotary displacement type gas service meter in sizes having a rated capacity of 5,000 cubic feet or less per hour at one-half inch water column differential, every five years;
  - (IV) rotary displacement type gas service meters in sizes having a rated capacity of more than 5,000 cubic feet per hour at a differential not to exceed two inches water column, the frequency of testing stated in the utility's tariff;
  - (V) orifice meters, not less than once each year; and
  - (VI) meter types not listed, not less than once each year.
- (e) In its tariff, a utility shall describe the utility's practices concerning the following:
  - (I) testing and adjustment of service meters at installation; and
  - (II) periodic testing after installation.

**4305. Meter Testing Upon Request.**

- (a) If a customer disputes the accuracy of a meter or disputes the billing that implicates the accuracy of a meter, the utility furnishing metered gas service shall inform the customer of their rights to have the meter tested as specified in this rule. Within 30 days of a customer's request, the utility shall test the meter's accuracy using standardized testing equipment. The test shall be conducted free of charge if the meter has not been tested within the previous 12 months; otherwise the utility may charge a fee for performing the test. The utility shall provide a written report of the test results to the customer and shall maintain the report on file for at least two years from the date of the test. If, upon completion of the test, the disputed meter is found to be inaccurate beyond the limits prescribed in rule 4302, it shall be deemed out of compliance.
- (b) Should a customer request and receive a meter test as prescribed in paragraph 4305(a) and continue to dispute the accuracy of the meter, or the billing that implicates the accuracy of the meter, the utility shall give notice to the customer of his or her right to request independent testing of the meter. The customer's right to request independent testing of the meter shall expire on the 30<sup>th</sup> day after the date of the utility's notice. Upon the customer's request, the utility shall make the disputed meter available for independent testing by a qualified meter testing facility of the customer's choosing. The customer is not entitled to take physical possession of the disputed meter. To be a qualified meter testing facility, the testing facility must be capable of testing the meter to meet all meter standards and requirements required by these rules.

- (c) If, upon completion of an independent test as prescribed in paragraph 4305(b), the disputed meter is found to be accurate within the limits of rule 4302, the customer shall bear all costs associated with conducting the independent test. If, upon completion of an independent test as prescribed in paragraph 4305(b), the disputed meter is found to be inaccurate beyond the limits prescribed in rule 4302, the meter shall be deemed out of compliance and the utility shall bear all costs associated with conducting the independent test.
- (d) In its tariff, a utility shall include any fees associated with customer-requested meter testing conducted within 12 months of a prior test.
- (e) If a meter is deemed out of compliance under this rule, the utility shall either inform the customer of his or her right to request a refund pursuant to rule 4402 or unilaterally issue the refund.

**4306. Records of Tests and Meters.**

- (a) For each meter owned or installed, a utility shall maintain a record showing the date of purchase, the manufacturer's serial number, the record of the present or previously installed location, and the date and results of the last test performed by the utility. This record shall be retained for the life of the meter plus 30 months.
- (b) Whenever a meter is tested either on request or upon complaint, the test record shall include the information necessary for identifying the meter, the reason for making the test, the reading of the meter if removed from service, the result of the test, and all data taken at the time of the test in a sufficiently complete form to permit the convenient checking of the methods employed and the calculations made. This record shall be retained for at least two years.

**4307- 4308. [Reserved].**

**4309. Meter Reading.**

- (a) Upon a customer's request, a utility shall provide written documentation showing the date of the most recent reading of the customer's meter and the total usage expressed in cubic feet or other unit of service recorded. On request, a utility supplying metered service shall explain to a customer in a clear non-technical statement its method of reading the customer's meter.
- (b) A utility shall include in its tariff a clear statement describing when meters will be read by the utility and the circumstances, if any, under which the customer must read the meter and submit the data to the utility. This statement shall specify in detail the procedure that the customer must follow and shall specify all special conditions that apply to each class of service.
- (c) Absent good cause, a utility shall read a meter monthly. For good cause shown, a utility shall read a meter at least once every six months.

**4310. – 4399. [Reserved]**

## **BILLING AND SERVICE**

### **4400. Applicability.**

Rules 4400 through 4412 apply to residential customers, small commercial customers and agricultural customers served pursuant to a LDC's rates or tariffs. Rules 4400 through 4405 and rules 4407 through 4412 shall not apply to customers served under a LDC's transportation rates or tariffs. In its tariffs, a LDC shall define "residential," "small commercial" and "agricultural" customers to which these rules apply. The LDC may elect to apply the same or different terms and conditions of service to other customers.

### **4401. Billing Information and Procedures.**

- (a) All bills issued to customers for metered service furnished shall show:
- (I) the dates and meter readings beginning and ending the period during which service was rendered;
  - (II) an appropriate rate or rate code identification for each separate rate component charged to the bill. Each component shall be designated on the bill in a manner such that the rate or charge can be identified clearly when referencing approved rates found in the utility's tariff;
  - (III) the net amount due for regulated charges;
  - (IV) the date by which payment is due, which shall not be earlier than 15 days after the mailing or the hand-delivery of the bill;
  - (V) a distinct marking to identify an estimated bill;
  - (VI) the total amount of all payments or other credits made to the customer's account during the billing period;
  - (VII) any past due amount. Unless otherwise stated in a tariff or Commission rule, an account becomes "past due" on the 31st day following the due date of current charges;
  - (VIII) the identification of, and amount due for, unregulated charges, if applicable;
  - (IX) any transferred amount or balance from any account other than the customer's current account; and
  - (X) all other essential facts upon which the bill is based, including factors and constants, as applicable.
- (b) A utility that bills for unregulated services or goods shall allocate partial payments first to regulated charges and then to unregulated charges or non-tariff charges and to the oldest balance due separately within each category.



- (c) A utility that transfers to a customer a balance from the account of a person other than that customer shall have in its tariffs the utility's benefit of service transfer policies and criteria. The tariffs shall contain an explanation of the process by which the utility will verify, prior to billing a customer under the benefit of service tariff, that the person to be billed in fact received the benefit of service.
- (d) A utility may transfer a prior unpaid debt to a customer's bill if the prior bill was in the name of the customer and the utility has informed the customer of the transferred amount and of the source of the unpaid debt (for example, and without limitation, the address of the premises to which service was provided and the period during which service was provided).
- (e) If it is offered in a tariff, upon request from a customer and where it is technically feasible, a utility may have the option to provide electronic billing (e-billing), in lieu of a printed bill, to the requesting customer. If a utility offers the option of e-billing, the following shall apply:
  - (I) the utility shall obtain the affirmative consent of a customer to accept such a method of billing in lieu of printed bills;
  - (II) the utility shall not charge a fee for billing through the e-billing option;
  - (III) the utility shall not charge a fee based on customer payment options that is different from the fee charged for the use of the same customer payment options by customers who receive printed bills; and
  - (IV) a bill issued electronically shall contain the same disclosures and Commission-required information as those contained in the printed bill provided to other customers.

**4402. Adjustments for Meter and Billing Errors.**

- (a) A utility shall adjust a customer's bill(s) for gas incorrectly metered or billed as follows.
  - (I) When, upon any meter accuracy test, a meter is found to be running slow in excess of error tolerance levels allowed under rule 4302, the utility may charge for one-half of the under-billed amount for the period dating from the discovery of the meter error back to the previous meter test, with such period not to exceed six months.
  - (II) When, upon any meter accuracy test, a meter is found to be running fast in excess of error tolerance levels allowed under rule 4302, the utility shall refund one-half of the excess charge for the period dating from the discovery of the meter error back to the previous meter test, with such period not to exceed two years.
  - (III) When a meter does not register, registers intermittently, or partially registers for any period, the utility may estimate, using the method stated in its tariff, a charge for the gas used based on amounts metered to the customer over a similar period in previous years. The period for which the utility charges the estimated amount shall not exceed six months.

- (IV) In the event of under-billings not provided for in subparagraph (a)(I) or (III) of this rule (such as, but not limited to, an incorrect multiplier, an incorrect register, or a billing error), the utility may charge for the period during which the under-billing occurred, with such period not to exceed six months.
- (V) In the event of over-billings not provided for in subparagraph (a)(II) of this rule, the utility shall refund for the period during which the over-billing occurred, with such period not to exceed two years.
- (b) The periods set out in paragraph (a) of this rule shall commence on the earliest date on which either the customer notifies the utility or the utility notifies the customer of a meter or billing error, the customer informs the utility of a billing or metering error, or a dispute based on a billing or metering error, or the customer submits an informal complaint to the Consumer Assistance Unit of the Commission. <http://www.colorado.gov/pacific/dora/file-consumer-complaint>.
- (c) In the event of an over-billing, the customer may elect to receive the refund as a credit to future billings or as a one-time payment. If the customer elects a one-time payment, the utility shall make the refund within 30 days. Such over-billings shall not be subject to interest.
- (d) In the event of under-billing, the customer shall be eligible and may elect to enter into a payment arrangement on the under-billed amount. The payment arrangement shall be equal in length to the length of time during which the under-billing occurred. Such under-billings shall not be subject to interest.

**4403. Applications for Service, Customer Deposits, and Third-Party Guarantee Arrangements.**

- (a) A utility shall process an application for utility service which is made either orally or in writing and shall apply nondiscriminatory criteria with respect to the requirement of a deposit prior to commencement of service.
- (b) If billing records are available for a customer who has received past service from the utility, the utility shall not require that person to make new or additional deposits to guarantee payment of current bills unless the records indicate recent or substantial delinquencies. All customers shall be treated without undue discrimination with respect to deposit requirements, and such requirements shall be specifically stated in to the utility's tariff.
- (c) A utility shall not require a deposit from an applicant for service who provides written documentation of a 12 consecutive month good credit history from the utility from which that person received similar service. For purposes of this paragraph, the 12 consecutive months must have ended no earlier than 60 days prior to the date of the application for service.
- (d) If a utility uses credit scoring to determine whether to require a deposit from an applicant for service or a customer, the utility shall have a tariff which describes, for each scoring model that it uses, the credit scoring evaluation criteria and the credit score limit which triggers a deposit requirement.
- (e) All utilities requiring deposits shall offer customers at least one non-cash alternative that does not require the use of the customer's social security number, in lieu of a cash deposit.

- (f) If a utility uses credit scoring, prior payment history with the utility, or customer-provided prior payment history with a like utility as a criterion for establishing the need for a deposit, the utility shall include in its tariff the specific evaluation criteria which trigger the need for a deposit.
- (g) If a utility denies an application for service or requires a deposit as a condition of providing service, the utility immediately shall inform the applicant for service of the decision and shall provide, within three business days, a written explanation to the applicant for service stating the specific reasons the application for service has been denied or a deposit is required.
- (h) No utility shall require any surety other than either a deposit to secure payment for utility services or a third-party guarantee of payment in lieu of a deposit. In no event shall the furnishing of utility services or extension of utility facilities, or any indebtedness in connection therewith, result in a lien, mortgage, or other interest in any real or personal property of the customer unless such indebtedness has been reduced to a judgment. Should the guarantor terminate service or terminate the third party guarantee before the customer has established a satisfactory payment record for 12 consecutive months, the utility, applying the criteria contained in its tariffs, may require a deposit or a new third party guarantor.
- (i) A deposit shall not exceed an amount equal to an estimated 90 days' bill of the customer, except in the case of a customer whose bills are payable in advance of service, in which case the deposit shall not exceed an estimated 60 days' bill of the customer. The deposit may be in addition to any advance, contribution in aid of construction or guarantee required by the utility tariff in connection with construction of lines or facilities, as provided in the extension policy in the utility's tariffs.
- (j) A utility receiving deposits shall maintain records showing:
  - (I) the name of each customer making a deposit;
  - (II) the amount and date of the deposit;
  - (III) each transaction, such as the payment of interest or interest credited, concerning the deposit;
  - (IV) each premise where the customer receives service from the utility while the deposit is retained by the utility;
  - (V) if the deposit was returned to the customer, the date on which the deposit was returned to the customer; and
  - (VI) if the unclaimed deposit was paid to the energy assistance organization, the date on which the deposit was paid to the energy assistance organization.
- (k) In its tariff, a utility shall clearly state its customer deposit policy for establishing or maintaining service. The tariff shall state the circumstances under which a deposit will be required and the circumstances under which it will be returned.

- (l) A utility shall issue a receipt to every customer from whom a deposit is received. No utility shall refuse to return a deposit or any balance to which a customer may be entitled solely on the basis that the customer is unable to produce a receipt.
- (m) The payment of a deposit shall not relieve any customer from the obligation to pay current bills as they become due. A utility is not required to apply any deposit to any indebtedness of the customer to the utility, except for utility services due or past due after service is terminated.
- (n) A utility shall pay simple interest on a deposit at the percentage rate per annum as calculated by the Commission staff and in the manner provided in this paragraph.
  - (I) At the request of the customer, the interest shall be paid to the customer either on the return of the deposit or annually. The simple interest on a deposit shall be earned from the date the deposit is received by the utility to the date the customer is paid. At the option of the utility, interest payments may be paid directly to the customer or credited to the customer's account.
  - (II) The simple interest to be paid on a deposit during any calendar year shall be at a rate equal to the average for the period October 1 through September 30 (of the immediately preceding year) of the 12 monthly average rates of interest expressed in percent per annum, as quoted for one-year United States Treasury constant maturities, as published in the Federal Reserve Bulletin, by the Board of Governors of the Federal Reserve System. Each year, the Commission staff shall compute the interest rate to be paid. If the difference between the existing customer deposit interest rate and the newly calculated customer deposit interest rate is less than 25 basis points, the existing customer deposit interest rate shall continue for the next calendar year. If the difference between the existing customer deposit interest rate and the newly calculated customer deposit interest rate is 25 basis points or more, the newly calculated customer deposit interest rate shall be used. The Commission shall send a letter to each utility stating the rate of interest to be paid on deposits during the next calendar year. Annually following receipt of Commission staff's letter, if necessary, a utility shall file by advice letter or application, as appropriate, a revised tariff, effective the first day of January of the following year, or on an alternative date set by the Commission, containing the new rate of interest to be paid upon customers' deposits, except when there is no change in the rate of interest to be paid on such deposits.
- (o) A utility shall have tariffs concerning third-party guarantee arrangements and, pursuant to those tariffs, shall offer the option of a third party guarantee arrangement for use in lieu of a deposit. The following shall apply to third-party guarantee arrangements:
  - (I) an applicant for service or a customer may elect to use a third-party guarantor in lieu of paying a deposit;
  - (II) the third-party guarantee form, signed by both the third-party guarantor and the applicant for service or the customer, shall be provided to the utility;
  - (III) the utility may refuse to accept a third-party guarantee if the guarantor is not a customer in good standing at the time of the presentation of the guarantee to the utility;

- (IV) the amount guaranteed shall not exceed the amount which the applicant for service or the customer would have been required to provide as a deposit;
  - (V) the guarantee shall remain in effect until the earlier of the following occurs:
    - (A) the guarantee is terminated in writing by the guarantor;
    - (B) if the guarantor was a customer at the time of undertaking the guarantee, the guarantor ceases to be a customer of the utility; or
    - (C) the customer has established a satisfactory payment record, as defined in the utility's tariffs, for 12 consecutive months.
  - (VI) Should the guarantor terminate service or terminate the third party guarantee before the customer has established a satisfactory payment record for 12 consecutive months, the utility, applying the criteria contained in its tariffs, may require a deposit or a new third party guarantor.
- (p) A utility shall pay all unclaimed monies, as defined in § 40-8.5-103(5), C.R.S., that remain unclaimed for more than two years to the energy assistance organization. "Unclaimed monies" shall not include undistributed refunds for overcharges subject to other statutory provisions and rules and credits to existing customers from cost adjustment mechanisms.
- (I) Monies shall be deemed unclaimed and presumed abandoned when left with the utility for more than two years after termination of the services for which the deposit or the construction advance was made or when left with the utility for more than two years after the deposit or the construction advance becomes payable to the customer pursuant to a final Commission order establishing the terms and conditions for the return of such deposit or advance and the utility has made reasonable efforts to locate the customer.
  - (II) Interest on a deposit shall accrue at the rate established pursuant to paragraph (n) of this rule commencing on the date on which the utility receives the deposit and ending on the date on which the deposit is paid to the energy assistance organization. If the utility does not pay the unclaimed deposit to the energy assistance organization within four months of the date on which the unclaimed deposition is deemed to be unclaimed or abandoned pursuant to subparagraph (p)(I) of this rule, then at the conclusion of the four-month period, interest shall accrue on the unclaimed deposit at the rate established pursuant to paragraph (n) of this rule plus six percent.
  - (III) If payable under the utility's line extension tariff provisions, interest on a construction advance shall accrue at the rate established pursuant to paragraph (n) of this rule commencing on the date on which the construction advance is deemed to be owed to the customer pursuant to the utility's extension policy and ending on the date on which the construction advance is paid to the energy assistance organization. If the utility does not pay the unclaimed construction advance to the energy assistance organization within four months of the date on which the unclaimed construction advance is deemed to be unclaimed or abandoned pursuant to subparagraph (p)(I) of this rule, then at the conclusion of the four-month period, interest shall accrue on the unclaimed construction advance at the rate established pursuant to paragraph (n) of this rule plus six percent.

- (q) A utility shall resolve all inquiries regarding a customer's unclaimed monies and shall not refer such inquiries to the energy assistance organization.
- (r) If a utility has paid unclaimed monies to the energy assistance organization, a customer later makes an inquiry claiming those monies, and the utility resolves the inquiry by paying those monies to the customer, the utility may deduct the amount paid to the customer from future funds submitted to the energy assistance organization.

**4404. Installment Payments.**

- (a) A utility shall make a budget or level payment plan available for its customers and have such plan clearly defined in its tariff.
- (b) A utility shall have in its tariff an installment payment plan which permits a customer to make installment payments if one of the following applies.
  - (I) The plan is to pay regulated charges from past billing periods and the past due amount arises solely from events under the utility's control (such as, without limitation, meter malfunctions, billing errors, utility meter reading errors, or failures to read the meter, except where the customer refuses to read the meter and it is not readily accessible to the utility). A utility shall advise a customer who is eligible for this type of plan of the customer's eligibility. At the request of the customer and at the customer's discretion, an installment payment plan under this subparagraph shall extend over a period equal in length to that during which the errors were accumulated and shall not include interest.
  - (II) The customer pays at least ten percent of the amount shown on the notice of discontinuance for regulated charges and enters into an installment payment plan on or before the expiration date of the notice of discontinuance.
  - (III) The customer pays at least ten percent of any regulated charges amount more than 30 days past due and enters into an installment payment plan on or before the last day covered by a medical certification. A customer who has entered into and failed to abide by an installment payment plan prior to receiving a medical certification shall pay all amounts that were due for regulated charges up to the date on which the customer presented a medical certification which meets the requirements of subparagraph 4407(e)(IV) and then may resume the installment payment plan.
  - (IV) If service has been disconnected, the customer pays at least any collection and reconnection charges and enters into an installment payment plan. This subparagraph shall not apply if service was discontinued because the customer breached a prior payment arrangement.
- (c) Installment payment plans shall include the following amounts that are applicable at the time the customer requests a payment arrangement:
  - (I) the unpaid remainder of amounts due for regulated charges shown on the notice of discontinuance;

- (II) any amounts due for regulated charges not included in the amount shown on the notice of discontinuance which have since become more than 30 days past due;
  - (III) all current regulated charges contained in any bill which is past due but is less than 30 days past the due date;
  - (IV) any new regulated charges contained in any bill which has been issued but is not past due;
  - (V) any regulated charges which the customer has incurred since the issuance of the most recent monthly bill;
  - (VI) any collection fees as provided for in the utility's tariff, whether or not such fees have appeared on a regular monthly bill;
  - (VII) any deposit, whether already billed, billed in part, or required by the utility's tariff, due for discontinuance or delinquency or to establish initial credit, other than a deposit required as a condition of initiating service; and
  - (VIII) any other regulated charges or fees provided in the utility's tariff (including without limitation miscellaneous service charges, investigative charges, and checks returned for insufficient funds charges), whether or not they have appeared on a regular monthly bill.
- (d) Within seven calendar days of entering into a payment arrangement with a customer, a utility shall provide the customer with this rule and a statement describing the payment arrangement. The statement describing the payment arrangement shall include the following:
- (I) the terms of the payment plan; and
  - (II) a description of the steps which the utility will take if the customer does not abide by payment plan.
- (e) Except as provided in subparagraph (b)(l) of this rule, an installment payment plan shall consist, at a minimum, of equal monthly installments for a term selected by the customer but not to exceed six months. In the alternative, the customer may choose a modified budget billing, level payment, or similar tariff payment arrangement in which the total due shall be added to the preceding year's total billing to the customer's premises, modified for any base rate or cost adjustment changes. The resulting amount shall be divided and billed in 11 equal monthly budget billing payments, followed by a settlement billing in the twelfth month, or shall follow other payment-setting practices consistent with the tariff plan available.

- (f) For an installment payment plan entered into pursuant to this rule, the first monthly installment payment, and with the new charges (unless the new charges have been made part of the arrangement amount) shall be due on a date which is not earlier than the next regularly-scheduled due date of the customer who is entering into the installment payment plan. Succeeding installment payments, together with the new charges, shall be due in accordance with the due date established in the installment payment plan. Any payment not made on the due date established in the installment payment plan shall be considered in default. Any new charges that are not paid by the due date shall be considered past due, excluding those circumstances covered in subparagraph (b)(I) of this rule.
- (g) This rule shall not be construed to prevent a utility from offering any other installment payment plan terms to avoid discontinuance or terms for restoration of service, provided the terms are at least as favorable to the customer as the terms set out in this rule.

**4405. Service, Rate, and Usage Information.**

- (a) In addition to the requirement found in rule 1206, a utility shall inform its customers of any change proposed or made in any term or condition of its service if that change or proposed change will affect the quality of the service provided.
- (b) A utility shall transmit information provided pursuant to this rule through the use of a method (such as, without limitation, bill inserts or periodic direct mail) that will assure receipt by each customer.
- (c) Upon request, a utility shall provide the following information to a customer.
  - (I) A clear and concise explanation of the existing rate schedule applicable to the customer, the rate components for that rate schedule, and an explanation of how those components are calculated and applicable to the customer. This shall be provided within ten days of a customer's request or, in the case of a new customer, within 60 days of the commencement of service.
  - (II) A clear and concise statement of the customer's actual consumption or degree-day adjusted consumption of gas for each billing period during the prior year, unless such consumption data are not reasonably ascertainable by the utility.
  - (III) A clear and concise explanation of the terms and conditions of service applicable to the customer.

**4406. Itemized Billing Components.**

- (a) A utility shall provide itemized gas cost information to all customers commencing with the first complete billing cycle in which the new rates are in effect. The information may be provided in the form of a bill insert or a separate mailing.
- (b) The information provided pursuant to this rule shall include the following:
  - (I) the per-unit and fixed service rates to be billed to the customer;



- II) the per-unit and monthly gas commodity costs for that customer;
- (III) the per-unit and monthly costs of upstream services for that customer; and
- (IV) the monthly gas demand side management costs for that customer.

**4407. Discontinuance of Service.**

- (a) A utility shall not discontinue the service of a customer for any reason other than the following:
  - (I) nonpayment of regulated charges;
  - (II) fraud or subterfuge;
  - (III) service diversion;
  - (IV) equipment tampering;
  - (V) safety concerns;
  - (VI) discontinuance ordered by any appropriate governmental authority; or
  - (VII) properly discontinued service being restored by someone other than the utility when the original cause for proper discontinuance has not been cured.
- (b) A utility shall not discontinue service for nonpayment of any of the following:
  - (I) any amount which has not appeared on a regular monthly bill or which is not past due. Unless otherwise stated in a tariff or Commission rule, an account becomes "past due" on the 31st day following the due date of current charges;
  - (II) any amount due on another account now or previously held or guaranteed by the customer, or with respect to which the customer received service, unless the amount has first been transferred either to an account which is for the same class of service or to an account which the customer has agreed will secure the other account. Any amount so transferred shall be considered due on the regular due date of the bill on which it first appears and shall be subject to notice of discontinuance as if it had been billed for the first time;
  - (III) any amount due on an account on which the customer is or was neither the customer of record nor a guarantor, or any amount due from a previous occupant of the premises. This subparagraph does not apply if the customer is or was obtaining service through fraud or subterfuge or if paragraph 4401(c) applies;
  - (IV) any amount due on an account for which the present customer is or was the customer of record, if another person established the account through fraud or subterfuge and without the customer's knowledge or consent;

- (V) any delinquent amount, unless the utility can supply billing records from the time the delinquency occurred;
  - (VI) any debt except that incurred for service rendered by the utility in Colorado; or
  - (VII) any unregulated charge.
- (c) If the utility discovers any connection or device installed on the customer's premises, including any energy-consuming device in the proximity of the utility's meter, which would prevent the meter from registering the actual amount of energy used, the utility shall do one of the following.
- (I) Remove or correct such devices or connections. If the utility takes this action, it shall leave at the premises a written notice which advises the customer of the violation, of the steps taken by the utility to correct it, and of the utility's ability to bill the customer for any estimated energy consumption not properly registered. This notice shall be left at the time the removal or correction occurs.
  - (II) Provide the customer with written notice that the device or connection must be removed or corrected within 15 days and that the customer may be billed for any estimated energy consumption not properly registered. If the utility elects to take this action and the device or connection is not removed or corrected within the 15 days permitted, then within seven calendar days from the expiration of the 15 days, the utility shall remove or correct the device or connection pursuant to subparagraph (c)(I) of this rule.
- (d) If a utility discovers evidence that any utility-owned equipment has been tampered with or that service has been diverted, the utility shall provide the customer with written notice of the discovery. The written notice shall inform the customer of the steps the utility will take to determine whether non-registration of energy consumption has or will occur and shall inform the customer that the customer may be billed for any estimated energy consumption not properly registered. The utility shall mail or hand-deliver the written notice within three calendar days of making the discovery of tampering or service diversion.
- (e) A utility shall not discontinue service, other than to address safety concerns, if one of the following is met:
- (I) If a customer at any time tenders full payment in accordance with the terms and conditions of the notice of discontinuance to a utility employee authorized to receive payment. Payment of a charge for a service call shall not be required to avoid discontinuance.
  - (II) If a customer pays, on or before the expiration date of the notice of discontinuance, at least one-tenth of the amount shown on the notice and enters into an installment payment plan with the utility, as provided in rule 4404.
  - (III) If it is between 12 Noon on Friday and 8 a.m. the following Monday; between 12 Noon on the day prior to and 8:00 a.m. on the day following any state or federal holiday; or between 12 Noon on the day prior to and 8:00 a.m. on the day following any day during which the utility's local office is not open.

- (IV) Medical emergencies.
- (A) A utility shall postpone discontinuance of gas service to a residential customer for 60 days from the date of a medical certificate issued by a Colorado-licensed physician or health care practitioner acting under a physician's authority which evidences that discontinuance of service will aggravate an existing medical emergency or create a medical emergency for the customer or a permanent resident of the customer's household. The customer may receive a single 30-day extension by providing a second medical certification prior to the expiration of the original 60-day period. A customer may invoke this subparagraph 4407(e)(IV)(A) only once in any twelve consecutive months.
  - (B) As a condition of obtaining a new installment payment plan on or before the last day covered by a medical certificate, a customer who had already entered into a payment arrangement, but had broken the arrangement prior to seeking a medical certification, may be required to pay all amounts that were due up to the date of the original medical certificate as a condition of obtaining a new payment arrangement. At no time shall a payment from the customer be required as a condition of honoring a medical certificate.
  - (C) The certificate of medical emergency shall be in writing, sent to the utility from the office of a licensed physician, and show clearly the name of the customer or individual whose illness is at issue; the Colorado medical identification number, phone number, name, and signature of the physician or health care practitioner acting under a physician's authority certifying the medical emergency. Such certification shall be incontestable by the utility as to the medical judgment, although the utility may use reasonable means to verify the authenticity of such certification.

**4408. Notice of Discontinuance.**

- (a) Except as provided in paragraphs (g) and (h) of this rule, a utility shall provide, by first class mail or by hand-delivery, written notice of discontinuance of service at least 15 days in advance of any proposed discontinuance of service. The heading shall contain, in bold font and capital letters, the following warning:
- THIS IS A FINAL NOTICE OF DISCONTINUANCE OF UTILITY SERVICE AND  
CONTAINS IMPORTANT INFORMATION ABOUT YOUR LEGAL RIGHTS AND  
REMEDIES. YOU MUST ACT PROMPTLY TO AVOID UTILITY SHUT OFF.**
- (b) The body of the notice of discontinuance under paragraph (a) of this rule shall at a minimum advise the customer of the following:
- (I) the reason for the discontinuance of service and of the particular terms of service and rule (if any) which has been violated;
  - (II) the amount past due for utility service, deposits, or other regulated charges, if any;

- (III) the date by which an installment payment plan must be entered into or full payment must be received in order to avoid discontinuance of service;
  - (IV) how and where the customer can pay or enter into an installment payment plan prior to the discontinuance of service;
  - (V) that the customer may avoid discontinuance of service by entering into an installment payment plan with the utility pursuant to rule 4404 as described in the utility's applicable tariff;
  - (VI) that the customer has certain rights if the customer or a member of the customer's household is seriously ill or has a medical emergency;
  - (VII) that the customer has the right to dispute the discontinuance directly with the utility by contacting the utility, and how to contact the utility toll-free from within the utility's service area;
  - (VIII) that the customer has the right to make an informal complaint to the Commission in writing, by telephone, or in person, along with the Commission's address and local and toll-free telephone number;
  - (IX) that the customer has the right to file a formal complaint, in writing, with the Commission pursuant to rule 1302 and that this formal complaint process may involve a formal hearing;
  - (X) that in conjunction with the filing of a formal complaint, the customer has a right to file a motion for a Commission order ordering the utility not to disconnect service pending the outcome of the formal complaint process and that the Commission may grant the motion upon such terms as it deems reasonable, including but not limited to the posting of a deposit or bond with the utility or timely payment of all undisputed regulated charges;
  - (XI) that if service is discontinued for non-payment, the customer may be required, as a condition of restoring service, to pay reconnection and collection charges in accordance with the utility's tariff; and
  - (XII) that qualified low-income customers may be able to obtain financial assistance to assist with the payment of the utility bill and that more detailed information on that assistance may be obtained by calling the utility toll-free. The utility shall state its toll-free telephone number.
- (c) At the time it provides notice of discontinuance to the customer, a utility shall also provide written notice by first class mail or hand-delivery to any third-party the customer has designated in writing to receive notices of discontinuance or broken arrangement.
- (d) A discontinuance notice shall be printed in English and a specific language or languages other than English where the utility's service territory contains a population of at least ten percent who speak a specific language other than English as their primary language as determined by the latest U.S. Census information.

- (e) A utility shall explain and shall offer the terms of an installment payment plan to each customer who contacts the utility in response to a notice of discontinuance of service.
- (f) Following the issuance of the notice of discontinuance of service, and at least 24 hours prior to discontinuance of service, a utility shall attempt to give notice of the proposed discontinuance in person or by telephone both to the customer and to any third party the customer has designated in writing to receive such notices. If the utility attempts to notify the customer in person but fails to do so, it shall leave written notice of the attempted contact and its purpose.
- (g) If a customer has entered into an installment payment plan and has defaulted or allowed a new bill to remain unpaid past its due date, a utility shall provide, by first class mail or by hand-delivery, a written notice to the customer. The notice shall contain:
  - (I) a heading as follows: NOTICE OF BROKEN ARRANGEMENT
  - (II) statements that advise the customer:
    - (A) that the utility may discontinue service if it does not receive the monthly installment payment within ten days after the notice is mailed or hand-delivered;
    - (B) that the utility may discontinue service if it does not receive payment for the current bill within 30 days after its due date;
    - (C) that, if service is discontinued, the utility may refuse to restore service until the customer pays all amounts for regulated service more than 30 days past due and any collection or reconnection charges; and
    - (D) that the customer has certain rights if the customer or a member of the customer's household is seriously ill or has a medical emergency.
- (h) A utility is not required to provide notice under this rule if one of the following applies:
  - (I) the situation involves safety concerns;
  - (II) discontinuance is ordered by any appropriate governmental authority;
  - (III) either paragraph 4407(c) or 4407(d) applies; or
  - (IV) service, having been already properly discontinued, has been restored by someone other than the utility and the original cause for discontinuance has not been cured.
- (i) Where a utility knows that the service to be discontinued is used by customers in multi-unit dwellings, in places of business, or in a cluster of dwellings or places of business and the utility service is recorded on a single meter used either directly or indirectly by more than one unit, the utility shall issue notice as required in paragraphs (a) and (b) of this rule, except that:
  - (I) the notice period shall be 30 days;
  - (II) such notice may include the current bill;

- (III) the utility shall provide written notice to each individual unit, stating that a notice of discontinuance has been sent to the party responsible for the payment of utility bills for the unit and that the occupants of the units may avoid discontinuance by paying the next new bill in full within 30 days of its issuance and successive new bills within 30 days of issuance; and
- (IV) the utility shall post the notice in at least one of the common areas of the affected location.

**4409. Restoration of Service.**

- (a) Unless prevented from doing so by safety concerns, a utility shall restore, without additional fee or charge, any discontinued service which was not properly discontinued or restored as provided in rules 4407, 4408, and 4409.
- (b) Unless prevented by safety concerns, a utility shall restore service within 24 hours (excluding weekends and holidays), or within 12 hours if the customer pays any necessary after-hours charges established in tariffs, if the customer does any of the following:
  - (I) pays in full the amount for regulated charges shown on the notice and any deposit and/or fees as may be specifically required by the utility's tariff in the event of discontinuance of service;
  - (II) pays any reconnection and collection charges specifically required by the utility's tariff, enters into an installment payment plan, and makes the first installment payment, unless the cause for discontinuance was the customer's breach of such an arrangement;
  - (III) presents a medical certification, as provided in subparagraph 4407(e)(IV);
  - (IV) demonstrates to the utility that the cause for discontinuance, if other than non-payment, has been cured.

**4410. Refunds.**

- (a) A utility shall file an application for Commission approval of a refund plan if it seeks to refund monies of an amount that exceeds one half of one percent of the utility's prior year's total gross revenues as reported to the Commission in its most recent annual report. The utility may refund amounts to the appropriate customers or classes of customers of less than one half of one percent of the utility's prior year's gross revenues without Commission approval; however, such refunds are required to be noted in the utility's annual report when filed with the Commission pursuant to paragraph 4006(a).
- (b) The application for approval of a refund plan shall include, in the following order and specifically identified, the following information either in the application or in the appropriately identified attachments:
  - (I) all the information required in paragraphs 4002(b) and 4002(c);
  - (II) the reason for the proposed refund;

- (III) a detailed description of the proposed refund plan, including the type of utility service involved, the service area involved, the class(es) of customers to which the refund will be made, and the dollar amount (both the total amount and the amount to be paid to each customer class) of the proposed refund. The interest rate on the refund shall be the current interest rate in the applying utility's customer deposits tariff;
  - (IV) the date the applying utility proposes to start making the refund, which shall be no more than 60 days after the filing of the application; the date by which the refund will be completed; and the means by which the refund is proposed to be made;
  - (V) if applicable, a reference (by proceeding number, decision number, and date) to any Commission decision requiring the refund or, the order itself if the refund is to be made because of receipt of monies by the applying utility under the order of a court or of another state or federal agency;
  - (VI) a statement describing in detail the extent to which the applying utility has any financial interest in any other company involved in the refund plan;
  - (VII) a statement showing accounting entries under the Uniform System of Accounts; and
  - (VIII) a statement that, if the application is granted, the applying utility will file an affidavit verifying that the refund has been made in accordance with the Commission's decision.
- (c) A utility shall pay 90 percent of all undistributed balances, plus associated interest, to the energy assistance organization. For purposes of this rule, a refund is deemed undistributed if, after good faith efforts, a utility is unable to find the person entitled to a refund within the period of time fixed by the Commission in its decision approving the refund plan.
- (d) A utility shall pay an undistributed refund to the energy assistance organization within four months after the refund is deemed undistributed. A utility shall pay interest on an undistributed refund from the time it receives the refund until the refund is paid to the energy assistance organization. The interest rate shall be equal to the interest rate set by the Commission pursuant to paragraph 4403(m).
- (e) Whenever a utility makes a refund, it shall provide written notice to those customers that it believes may be master meter operators. The notice shall contain:
- (I) the definition of master meter operator, as set forth in these rules;
  - (II) a statement regarding a mater meter operator's obligation to do the following:
    - (A) to notify its end users of their right to claim, within 90 days, their proportionate share of the refund; and
    - (B) after 90 days, if the unclaimed balance exceeds \$100, to remit the unclaimed balance to the energy assistance organization.
- (f) A utility shall resolve all inquiries regarding a customer's undistributed refund and shall not refer such inquiries to the energy assistance organization.

- (g) If a utility has paid an undistributed refund to the energy assistance organization, a customer later makes an inquiry claiming that refund, and the utility resolves the inquiry by paying that refund to the customer, the utility may deduct the amount paid to the customer from future funds submitted to the energy assistance organization.

**4411. Low-Income Energy Assistance Act.**

- (a) Scope and applicability.
- (I) Rule 4411 is applicable to gas and combined gas and electric utility providers except those exempted under (II) or (III). Pursuant to §§ 40-8.7-101 through 111, C.R.S., utilities are required to provide an opportunity for their customers to contribute an optional amount through the customers' monthly billing statement.
- (II) Municipally owned gas or gas and electric utilities are exempt if:
- (A) the utility operates an alternative energy assistance program to support its low-income customers with their energy needs and self-certifies to the Organization through written statement that its program meets the following criteria:
- (i) the amount and method for funding of the program has been determined by the governing body; and
- (ii) the program monies will be collected and distributed in a manner and under eligibility criteria determined by the governing body for the purpose of residential energy assistance to customers who are challenged with paying energy bills for financial reasons, including seniors on fixed incomes, individuals with disabilities, and low-income individuals, or,
- (B) the governing body of the utility determines its service area has a limited number of people who qualify for energy assistance and self-certifies to the Organization via written statement such determination.
- (III) A municipally owned gas or gas and electric utility not exempt under subparagraph (a)(II) of this rule, is exempt if:
- (A) the utility designs and implements a procedure to notify all customers at least twice each year of the option to conveniently contribute to the Organization by means of a monthly energy assistance charge. Such procedure shall be approved by the governing utility. The governing body of such utility shall determine the disposition and delivery of the optional energy assistance charge that it collects on the following basis:
- (i) delivering the collections to the organization for distribution; or
- (ii) distributing the moneys under criteria developed by the governing body for the purpose set forth in subparagraph (a)(II)(A)(ii) of this rule;



- (B) alternatively, the utility provides funding for energy assistance to the Organization by using a source of funding other than the optional customer contribution on each customer bill that approximates the amount reasonably expected to be collected from an optional charge on customer's bills.
  - (IV) A municipally gas or gas and electric utility that is exempt under subparagraph (a)(III) of this rule shall be entitled to participate in the Organization's low-income assistance program.
  - (V) Gas or gas and electric utilities that desire a change in status must inform the Organization and file a notice to the Commission within 30 days prior to expected changes.
- (b) Definitions. The following definitions apply only in the context of rule 4411. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.
- (I) "Alternative energy assistance program" means a program operated by a municipally owned electric and gas utility or rural electric cooperative that is not part of the energy assistance program established pursuant to this statute.
  - (II) "Customer" means the named holder of an individually metered account upon which charges for electricity or gas are paid to a utility. "Customer" shall not include a customer that receives electricity or gas for the sole purpose of reselling the electricity or gas to others.
  - (III) "Energy assistance program" or "Program" means the Low Income Energy Assistance Program created by § 40-8.7-104, C.R.S., and designed to provide financial assistance, residential energy efficiency, and energy conservation assistance.
  - (IV) "Organization" means Energy Outreach Colorado, a Colorado nonprofit corporation.
  - (V) "Remittance device" means the section of a customer's utility bill statement that is returned to the utility company for payment. This includes but is not limited to paper payment stubs, web page files used to electronically collect payments, and electronic fund transfers.
  - (VI) "Utility" means a corporation, association, partnership, cooperative electric association, or municipally owned entity that provides retail electric service or retail gas service to customers in Colorado. "Utility" does not mean a propane company.
- (c) Plan implementation and maintenance.
- (I) Except as provided in paragraph 4411(a), each utility shall implement and maintain a customer opt-in contribution mechanism. The utility's opt-in mechanism shall include, at minimum, the following provisions.
    - (A) A description of the procedures the utility will use to notify its customers, including those customers that make payments electronically, about the opt-in provision. Utilities may combine their efforts to notify customers into a single

state-wide or region-wide effort consistent with the participating utilities communication programs. Each participating utility shall clearly identify its support of the combined communications program, with its corporate name and/or logo visible to the intended audience.

- (B) A description of the additional efforts the utility will use to inform its customers about the program to ensure that adequate notice of the opt-in provision is given to all customers. Notification shall include communication to all customers that the donation and related information will be passed through to the Organization.
- (C) A description of the check-off mechanism that will be displayed on the monthly remittance device to solicit voluntary donations. The remittance device shall include, at minimum, check-off categories of five dollars, ten dollars, twenty dollars, and “other amount”. The remittance device must also note the name of the program as the “voluntary energy assistance program,” or if the utility is unable to identify the name of the program individually, the utility shall use a general energy assistance identifier approved by the Commission.
- (D) A description or an example of how the utility will display the voluntary contribution as a separate line item on the customer’s monthly billing statement and how the voluntary contribution will be included in the total amount due. The line item must identify the contribution as “voluntary”.
- (E) A description of the notification process that the utility will use to ensure that once a utility customer opts into the program, the energy assistance contribution will be assessed on a monthly basis until the customer notifies the utility of the customer’s desire to stop contributing. The utility shall describe how it will manage participation in the program when customers miss one or more voluntary payment, or pay less than the pre-selected donation amount.
- (F) Identification of the procedures the utility will use to notify customers of their ability to cancel or discontinue voluntary contributions along with a description of the mechanism the utility will use to allow customers who make electronic payments to discontinue their participation in the opt-in program.
- (G) A description of the procedures the utility will use, where feasible, to notify customers participating in the program about the customer’s ability to continue to contribute when the customer changes their address within the utility’s service territory.
- (H) A description of the method the utility will use to provide clear, periodic, and cost-effective notice of the opt-in provision to its customers at least twice per year. Acceptable methods include, but are not limited to, bill inserts, statements on the bill or envelope, and other utility communication pieces.
- (I) A description of the start-up costs that the utility incurred in connection with the program along with supporting detailed justification for such costs. The description should include the utility’s initial costs of setting up the collection mechanism and reformatting its billing systems to solicit the optional contribution

but shall not include the cost of any notification efforts by the utility. Utilities may elect to recover all start-up costs before the remaining moneys generated by the program are distributed to the Organization or over a period of time from the funds generated by the program, subject to Commission review and approval.

- (J) An estimate of the on-going costs that the utility expects to incur in connection with the program along with supporting detailed justification for such costs. This estimate shall not include the cost of any notification efforts by the utility.
  - (K) A detailed justification for the costs identified in (I) and (J). As stated in § 40-8.7-104(3), C.R.S., the costs incurred must be reasonable in connection with the program.
  - (L) Utilities shall recover the start up cost and on-going cost of administration associated with the program from funds generated from the program. Insert and notification costs shall be considered in the utility's cost of service.
  - (M) A description of the procedures the utility will use to account for and process program donations separately from customer payments for utility services.
- (II) Each utility shall participate in the energy assistance program consistent with its plan approved by the Commission and shall provide the opportunity for its customers to make an optional energy assistance contribution on the monthly remittance device on their utility bill.
  - (III) The utility may submit an application to the Commission no later than April 1 of each year for approval of reimbursement costs the utility incurred for the program during the previous calendar year. Such application shall include a proposed schedule for the reimbursement of these costs to the utility. The applications shall include detailed supporting justification for approval of these costs. Such detailed justification includes, but is not limited to, copies of invoices and time sheets. Such applications shall not seek reimbursement of costs related to notification efforts. Participating utilities may request reimbursement costs for such notification efforts in base rate filings, subject to Commission review and approval.
  - (IV) A utility may seek modification of its initial plan or subsequent plans by filing an application with the Commission.
- (d) Fund administration.
- (I) At a minimum, each utility shall transfer the funds collected from its customers under the energy assistance program to the organization under the following schedule:
    - (A) for the funds collected during the period of January 1 to March 31 of each year, the utility shall transfer the collected funds to the Organization before May 1 of such year;

- (B) for the funds collected during the period of April 1 to June 30 of each year, the utility shall transfer the collected funds to the Organization before August 1 of such year;
  - (C) for the funds collected during the period of July 1 to September 30 of each year, the utility shall transfer the collected funds to the Organization before November 1 of such year;
  - (D) for the funds collected during the period of October 1 to December 31 of each year, the utility shall transfer the collected funds to the Organization before February 1 of the next year; and
  - (E) each utility shall maintain a separate accounting for all energy assistance program funds received by customers.
- (II) Each utility shall provide the organization with the following information.
- (A) How the funds collected for the previous calendar year were generated, including the number of customers participating in the program. Such report shall include a summary of the number of program participants and funds collected by month, and shall be provided by February 1 of each year.
  - (B) At each time funds are remitted, a listing of all program participants including the donor's name, billing address, and monthly donation amount. The participant information provided to the organization shall be used exclusively for complying with the requirements of § 40-8.7-101, C.R.S., et seq. and state and federal laws.
- (III) The Public Utilities Commission shall submit, as necessary, a bill for payment to the Organization for any administrative costs incurred pursuant to the program.
- (IV) The organization shall provide the Office of Consumer Counsel and the Public Utilities Commission with a copy of the written report that is described in § 40-8.7-110, C.R.S. This report shall not contain individual participant information.
- (e) Prohibition of disconnection. Utilities shall not disconnect a customer's gas service for non-payment of optional contribution amounts.

**4412. Gas Service Low-Income Program.**

- (a) Scope and applicability.
  - (I) Gas utilities with Colorado retail customers shall provide low-income energy assistance by offering rates, charges, and services that grant a reasonable preference or advantage to residential low-income customers, as permitted by § 40-3-106, C.R.S.
  - (II) Rule 4412 is applicable to investor-owned gas utilities subject to rate regulation by the Commission.

- (b) Definitions. The following definitions apply only in the context of rule 4412. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.
- (I) “Administrative cost” means the utility’s direct cost for labor (to include the cost of benefit loadings), materials, and other verifiable expenditures directly related to the administration and operation of the program not to exceed ten percent of the total cost of program credits applied against bills for current usage and pre-existing arrearages or \$10,000, whichever amount is greater.
  - (II) “Affordable percentage of income payment” means the amount of the participant’s annual bill deemed affordable under subparagraph 4412(e)(I).
  - (III) “Arrearage” means the past-due amount appearing, as of the date on which a participant newly enters the program, on the then most recent prior bill rendered to a participant for which they received the benefit of service.
  - (IV) “Colorado Energy Office” (CEO) means the Colorado Energy Office created in § 24-38.5-101, C.R.S.
  - (V) “Eligible low-income customer” means a residential utility customer who meets the household income thresholds pursuant to paragraph 4412(c).
  - (VI) “Fixed credit” means an annual bill credit established at the beginning of a participant’s participation in a program each year delivered as a monthly credit on each participant’s bill. The fixed credit is the participant’s full annual bill minus the participant’s affordable percentage of income payment obligation on the full annual bill.
  - (VII) “Full annual bill” means the current consumption of a participant billed at standard residential rates. The full annual bill of a participant is comprised of two parts: (1) that portion of the bill that is equal to the affordable percentage of income payment; and (2) that portion of the bill that exceeds the affordable percentage of income payment.
  - (VIII) “LEAP” means Low-Income Energy Assistance Program, a county-run, federally-funded, program supervised by the Colorado Department of Human Services, Division of Low-Income Energy Assistance.
  - (IX) “LEAP participant” means a utility customer who at the time of applying to participate in a program has been determined to be eligible for LEAP benefits by the Department during either the Department’s current six-month (November 1 – April 30) LEAP application period, if that period is open at the time the customer applies for program participation; or (the Department’s most recently closed six-month (November 1 – April 30) LEAP application period, if that period is closed at the time the customer applies to participate in the program and the Department’s next six-month (November 1 – April 30) LEAP application period has not yet opened, provided, however, that in order to retain status as a LEAP participant under this definition, the utility customer must apply to the Department during the Department’s next six-month (November 1 – April 30) LEAP benefit application period and be determined eligible for such benefits.

- (X) “Non-participant” means a utility customer who is not receiving low-income assistance under rule 4412.
  - (XI) “Participant” means an eligible low-income residential utility customer who is granted the reasonable preference or advantage through participation in a gas service low-income program.
  - (XII) “Percentage of Income Payment Plan” (PIPP) means a payment plan for participants that does not exceed an affordable percentage of their household income as set forth in subparagraph 4412(e)(I).
  - (XIII) “Program” means a gas service low-income program approved under rule 4412.
  - (XIV) “Program credits” means the amount of benefits provided to participants to offset the unaffordable portion of a participant’s utility bill and /or dollar amounts credited to participants for arrearage forgiveness.
  - (XV) “Unaffordable portion” means the amount of the estimated full annual bill that exceeds the affordable percentage of income payment.
- (c) Participant eligibility. Eligible participants are limited to those with a household income at or below 185 percent of the current federal poverty level, or, if the utility applies individual LEAP benefits to offset the costs of the unaffordable portion of the participating customer’s utility bill, the percent of the current federal poverty level set by the Colorado Department of Human Services, Division of Low-income Energy Assistance for eligibility in the LEAP program.
- (I) Gas utilities may obtain federal annual poverty level income amounts based on household size on the Colorado Department of Human Services, Division of Low Income Energy Assistance website at <https://sites.google.com/a/state.co.us/cdhs-leap/program-eligibility>.
  - (II) The utility shall obtain household income information from LEAP.
  - (III) If a participant’s household income is \$0, the utility may establish a process that verifies income on a more frequent basis.
  - (IV) Program participants shall not be required to make payment on their utility account as a condition of entering into the program.
- (d) Enrollment. Utilities shall be responsible for the methods by which participant enrollment in their approved low income program is obtained and sustained, however the utility should engage in enrollment processes that are efficient and attempt to maximize the potential benefits of participation in the low income program by low income customers.

- (e) Payment plan.
- (I) Participant payments for natural gas bills rendered to participants shall not exceed an affordable percentage of income payment. For accounts for which natural gas is the primary heating fuel, participant payments shall be no lower than two percent and not greater than three percent of the participant's household income.
  - (II) In the event that a primary heating fuel for any particular participant has been identified by LEAP, that determination shall be final.
  - (III) Notwithstanding the percentage of income limits established in subparagraph 4412(e)(I), a utility may establish minimum monthly payment amounts for participants with household income of \$0, provided that the participant's minimum payment for a natural gas account shall be no more than \$10.00 a month.
  - (IV) Full annual bill calculation. The utility shall be responsible for estimating a participant's full annual bill for the purpose of determining the unaffordable portion of the participant's full annual bill delivered as a fixed credit on the participant's monthly billing statement.
  - (V) Fixed credit benefit. The fixed credit shall be adjusted during a program year in the event that standard residential rates, including commodity or fuel charges change to the extent that the full annual bill at the new rates would differ from the full annual bill upon which the fixed credits are currently based by 25 percent or more.
  - (VI) Levelized budget billing participation. A utility shall enroll participants in its levelized budget billing program as a condition of participation in the program. Should a participant fail to meet monthly bill obligations and be placed by a utility in its regular delinquent collection cycle, the utility may remove the participant from levelized budget billing in accordance with the utility's levelized budget billing tariff.
  - (VII) Arrearage credits.
    - (A) Arrearage credits shall be applied to pre-existing arrearages.
    - (B) Arrearage credits shall be sufficient to reduce, when combined with participant copayments, if any, the pre-existing arrearages to \$0.00 over a period not less than one month and not more than twenty-four months.
    - (C) Application of an arrearage credit to a participant account may be conditioned by the utility on one or more of the following:
      - (i) the receipt of regular participant payments toward bills for current usage;  
or
      - (ii) the payment of a participant copayment toward the arrearages so long as the participant's copayment total dollar amount does not exceed one percent of gross household income.

- (D) Should the participant exit the program prior to the full forgiveness of all pre-existing arrearages, the amount of remaining pre-existing arrearages shall become due in accordance with the utilities tariff filed under rules 4401, 4407, and 4408.
  - (E) Pre-existing arrears under this subparagraph shall not serve as the basis for the termination of service for nonpayment or as the basis for any other utility collection activity while the customer is participating in the program.
  - (F) A participant may receive arrearage credits under this section even if that participant does not receive a credit toward current bills, if the participant enters into and maintains a levelized budget billing plan.
- (VIII) Portability of benefits. A participant may continue to participate without reapplication should the participant change service addresses, but remain within the service territory of the utility providing the benefit, provided that the utility may make necessary adjustments in the levelized budget billing amount to reflect the changed circumstances. A participant who changes service addresses and does not remain within the service territory of the utility providing the benefit must reapply to become a participant at the participant's new service address.
- (IX) Payment default provisions. Failure of a participant to make his or her monthly bill payments will result in a utility placing the participant in its regular collection cycle. Missed, partial or late payments shall not result in the removal of a participant from the program.
- (f) Program implementation.
- Each utility shall maintain effective terms and conditions in its tariffs on file with the Commission describing its low-income program.
- (g) Cost recovery.
- (I) Each utility shall include in its low income tariff terms and conditions how costs of the program will be recovered.
  - (II) Program cost recovery.
    - (A) Program cost recovery shall be based on a fixed monthly fee.
    - (B) The maximum impact on residential rates shall be no more than \$00.31 per month. [This rule was changed temporarily by Decision No. C20-0899.]
    - (C) In order to determine monthly rates applicable to rate classes other than residential, program costs shall be allocated to each retail rate based on each rate class's share of the test year revenue requirement established in the utility's last Phase II rate case, or under another reasonable methodology supported by quantifiable information. The monthly rate per this subparagraph to be charged each rate schedule customer shall be clearly stated on a tariff sheet.



- (D) Utilities shall separately account for the cumulative program cost recovery and cumulative program and administrative costs to determine if the net of program cost recovery and program and administrative cost are in balance during the program year.
  - (i) Beginning October 31, 2018 and in each year thereafter, the utility shall file a report with the Commission in the most recent miscellaneous proceeding for annual low-income filings detailing the net difference between program cost recovery and program costs as of September 30 of each year.
    - (1) Should the net difference of program cost recovery over program costs be greater than 50 percent derived in (ii) above, either positive or negative, and the utility is not currently at the maximum impact for non-participants, the utility shall file with the Commission an advice letter and tariff pages seeking approval for the rates determined in subparagraph 4412(g)(II)(D) in order to bring the projected recovery in balance for the ensuing 12 month period. The revised Residential charge shall not exceed the maximum impact for non-participants in subparagraph 4412(g)(II)(C).
- (III) The following costs are eligible for recovery by a utility as program costs:
  - (A) program credits or discounts applied against bills for current usage;
  - (B) program credits applied against pre-existing arrearages;
  - (C) program administrative costs; and
  - (D) Commission-sponsored program evaluation costs required under paragraph 4412(k).
- (IV) The utility shall apply, as an offset to cost recovery, all program expenses attributable to the program. Program expenses include utility operating costs; changes in the return requirement on cash working capital for carrying arrearages; changes in the cost of credit and collection activities directly related to low-income participants; and changes in uncollectable account costs for these participants.
- (V) LEAP grants.
  - (A) The utility shall apply energy assistance grants provided to the participant by the LEAP program to the dollar value of credits granted to individual program participants.
  - (B) A utility shall apply any energy assistance benefit granted to the participant by LEAP to that portion of the program participant's full annual bill that exceeds the participant's affordable percentage of income payment.

- (C) If the dollar value of the energy assistance grant is greater than the dollar value of the difference between the program participant's full annual bill and the participant's affordable percentage of income payment, the dollar amount by which the energy assistance grant exceeds the difference will be applied:
    - (i) first, to any pre-existing arrearages that at the time of the energy assistance grant continues to be outstanding; and
    - (ii) second, to the account of the program participant as a benefit to the participant.
  - (D) No portion of an energy assistance or LEAP grant provided to a program participant may be applied to the account of a participant other than the participant to whom the energy assistance grant was rendered.
- (h) Other programs. In addition to the utility's low-income program, with Commission approval, a utility may offer other rate relief options to eligible households.
- (I) Other programs offered by the utility under rule 4412 must be intended to reach low-income households that do not substantially benefit from the provisions of the low-income program. Such programs may take the form of discount rates, tiered discount rates or other direct bill relief methods where the low-income household benefitting from the program is granted a reasonable preference in tariffed rates assessed to all residential utility customers.
  - (II) Cost recovery for other programs combined with the Percentage of Income Payment Plan shall not exceed the maximum impact on residential rates described in subparagraph 4412(g)(II)(C).
- (i) Energy efficiency and weatherization.
- (I) The utility shall provide all program participants with information on energy efficiency programs offered by the utility or other entities and existing weatherization programs offered by the state of Colorado or other entities.
  - (II) The utility shall provide the Colorado Energy Office with the name and service address of participant households for which annual natural gas usage exceeds 600 therms annually.
- (j) Stakeholder engagement. A utility shall conduct annual meetings with low-income stakeholders for the purpose of seeking solutions to issues of mutual concern and aligning program practices with the needs of customers and other stakeholders.
- (k) Program evaluation. A triennial evaluation of the program provisions under rule 4412 beginning in 2019 shall be undertaken in order to review best practices in similar low income assistance programs in existence in other regulatory jurisdictions, as well as evaluate operation of each utility's program for effectiveness in achieving optimum support being provided to low income participants. The evaluation shall also recommend modifications if available that improve the delivery of benefits to participants and increase the efficiency and effectiveness of each program as they exist at the point of evaluation.

- (I) Procurement of the third-party vendor that will perform the evaluation will be undertaken by the Colorado Energy Office. The CEO shall seek the involvement of interested stakeholders including, but not limited to, Commission staff, all Commission regulated electric and gas utilities, LEAP, the Office of Consumer Counsel, and Energy Outreach Colorado in the design of the requirements regarding study focus and final reporting.
  - (II) Approval of the third-party vendor shall be the responsibility of the Commission. The CEO shall file with the Commission in the most recent annual report proceeding, a request for approval of the contract of the vendor selected. The Commission shall review and act on the request within 30 days.
  - (III) \$00.0013 per customer per month shall be set aside by the utility starting in the 2016-2017 program year in order to cover the cost of the program evaluation described in paragraph 4412(k).
  - (IV) The dollars resulting from the \$00.0013 charge shall be recovered as a program cost under subparagraph 4412(g)(III).
  - (V) The evaluation will be filed by Commission staff in the most recent miscellaneous proceeding for annual low income filings.
  - (VI) Staff and the CEO will assess the individual utilities' deferred balances set aside for the program evaluation starting in 2019 at the conclusion of the third program year and each three years thereafter and will determine the amounts each utility is to remit to the third party evaluator based on the contractual terms approved by the Commission for the evaluation.
- (I) Annual report. No later than December 31, of each year the utility shall file a report in the most recent miscellaneous proceeding established by the Commission to receive annual low income filings using the form available on the Commission's website, based on the 12-month period ending October 31 containing the following information:
- (I) monthly information on the program including number of participants, amount of benefit disbursement, type of benefit disbursement, LEAP benefits applied to the unaffordable portion of participant's bills, administrative costs, and revenue collection;
  - (II) the number of applicants for the program;
  - (III) the number of applicants qualified for the program;
  - (IV) the number of participants;
  - (V) the average assistance provided, both mean and median;
  - (VI) the maximum assistance provided to an individual participant;
  - (VII) the minimum assistance provided to an individual participant;

- (VIII) total cost of the program and the average rate impact on non-participants by rate class, including impact based on typical monthly consumption of both its residential and small business customers;
- (IX) the number of participants that had service discontinued as a result of late payment or non-payment, and the amount of uncollectable revenue from participants;
- (X) an estimate of utility savings as a result of the implementation of the program (e.g., reduction in trips related to discontinuance of service, reduction in uncollectable revenue, etc.);
- (XI) the average monthly and annual total natural gas consumption in PIPP participants' homes;
- (XII) the average monthly and annual total natural gas consumption in the utility's residential customer's homes;
- (XIII) the number of program participants referred to the weatherization program;
- (XIV) a description of the ways in which the program is being integrated with existing energy efficiency of DSM programs offered by the utility;
- (XV) a description of the ways in which the program is being integrated with existing weatherization programs offered by the state of Colorado;
- (XVI) a description of program outreach strategies and metrics that illustrate the effectiveness of each outreach strategy;
- (XVII) the number of participants at the start of the program year that the utility removed for any reason, the number of potential participants rejected because of the existence of a cap on the program, the period of arrearage time from date participants became eligible and were granted arrearage forgiveness, and the number of participants who came back as eligible participants in the program year after being eligible in a prior program year and were provided arrearage credits in the program year; and
- (XVIII) a narrative summary of the utility's recommended program modifications based on report findings.

**4413. – 4499. [Reserved].**

## **UNREGULATED GOODS AND SERVICES**

### **4500. Overview and Purpose.**

The purpose of these rules is to establish cost assignment and allocation principles to assist the Commission in setting just and reasonable rates and to ensure that utilities do not use ratepayer funds to subsidize non-regulated activities, in accordance with § 40-3-114, C.R.S. In order to promote these purposes, these rules also specify information that utilities must provide to the Commission. In providing for review of a utility's specific cost allocations in other states and jurisdictions, the rules merely

contemplate a methodology to allow interested parties to obtain complete information regarding cost allocations. These rules do not expressly or implicitly allow this Commission to order a utility to revise its cost allocations in other jurisdictions or states.

#### **4501. Definitions.**

The following special definitions apply only to rules 4501 through 4505. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- (a) “Activity” means a business activity, product or service whether offered by a Colorado utility, a division of a Colorado utility, or an affiliate of a Colorado utility.
- (b) “Allocate” or “Allocated” or “Cost Allocation” means to distribute a joint or common cost to or from more than one activity or jurisdiction.
- (c) “Assigned Costs” or “Cost Assignment” means a cost that is specifically identified with a particular activity or jurisdiction and charged directly to that activity or jurisdiction. At no point in the process of making the cost assignment is an allocation applied.
- (d) “Cost Assignment and Allocation Manual” (CAAM) means the indexed document filed by a utility with the Commission that describes and explains the cost assignment and allocation methods the utility uses to segregate and account for revenues, expenses, assets, liabilities, and rate base cost components assigned or allocated to Colorado jurisdictional activities. It includes the cost assignment and allocation methods to segregate and account for costs between and among jurisdictions, between regulated and non-regulated activities, and between and among utility divisions.
- (e) “Division” means an activity conducted by a Colorado utility but not through a legal entity separate from the Colorado utility. It includes the electric, gas, or thermal activities of a Colorado utility and any non-regulated activities provided by the Colorado utility.
- (f) “Fully Distributed Cost” (FDC) means the process of segregating, assigning, and allocating the revenues, expenses, assets, liabilities and rate base amounts recorded in the utility’s accounting books and records using cost accounting, engineering, and economic concepts, methods and standards. Fully distributed cost includes a return on investment in cases where assets are used.
- (g) “Fully Distributed Cost Study” is a cost study that reflects the result of the fully distributed revenues, expenses, assets, liabilities and rate base amounts for the Colorado utility to and from the different activities, jurisdictions, divisions, and affiliates using cost accounting, engineering, and economic concepts, methods, and standards.
- (h) “Incidental Services” means non-tariff or non-regulated services that have traditionally been offered incidentally to the provisions of tariff services where the revenues for all such services do not exceed:
  - (l) The greater of \$100,000 or one percent of the provider’s total annual Colorado operating revenues for regulated services; or,

- (II) Such amount established by the Commission considering the nature and frequency of the particular service.
- (i) “Jurisdictional” means having regulatory rate authority over a utility. Jurisdiction can be at a state or federal level.
- (j) “Regulated activity” means any activity that is offered as a public utility service as defined in Title 40, Articles 1 to 7 C.R.S., and is regulated by the Commission or regulated by another state utility commission or the FERC, or any non-regulated activity which meets the criteria specified in rules 4502(g).
- (k) “Non-regulated activity” means any activity that is not offered as a public utility service as defined in Title 40, Articles 1 to 7, C.R.S., and is not regulated by this Commission or another state utility commission or the FERC.
- (l) “Transaction” means the activity that results in the provision of products, services, or assets by one division or an affiliate to another division or an affiliate.

**4502. Cost Assignment and Allocation Principles.**

In determining fully distributed cost, the utility shall apply the following principles (listed in descending order of required application in paragraphs 4502 (a), (b) and (c) below).

- (a) Tariff services provided to an activity will be charged to the activity at the tariff rates.
- (b) If only one activity or jurisdiction causes a cost to be incurred, that cost shall be directly assigned to that activity or jurisdiction.
- (c) Costs that cannot be directly assigned to either regulated or non-regulated activities or jurisdictions will be described as common costs. Common costs shall be grouped into homogeneous cost categories designed to facilitate the proper allocation of costs between regulated and non-regulated activities or jurisdictions. Each cost category shall be fairly and equitably allocated between regulated and non-regulated activities or jurisdictions in accordance with the following principles.
  - (I) Cost causation. All activities or jurisdictions that cause a cost to be incurred shall be allocated a portion of that cost. Direct assignment of a cost is preferred to the extent that the cost can easily be traced to the specific activity or jurisdiction.
  - (II) Variability. If the fully distributed cost study indicates a direct correlation exists between a change in the incurrence of a cost and cost causation, that cost shall be allocated based upon that relationship.
  - (III) Traceability. A cost may be allocated using a measure that has a logical or observable correlation to all the activities or jurisdictions that cause the cost to be incurred.
  - (IV) Benefit. All activities or jurisdictions that benefit from a cost shall be allocated a portion of that cost.

- (V) Residual. The residual of costs left after either direct or indirect assignment or allocation shall be allocated based upon an appropriate general allocator to be defined in the utility's CAAM.
- (d) For cost assignment and allocation purposes, the value of all transactions from the Colorado utility to a non-regulated activity shall be determined as follows:
- (I) if the transaction involves a product or service provided by the utility pursuant to tariff, the value of the transaction shall be at the tariff rate;
  - (II) if the transaction involves a product or service that is not provided pursuant to a tariff, the value of the transaction shall be the higher of the utility's fully distributed cost or market price. Market price shall be either the price charged by the utility, or if this condition cannot be met, the lowest price charged by another person for a comparable product or service; or
  - (III) if the transaction involves the sale of an asset, the value of the transaction shall be the higher of net-book cost or market price. If the transaction involves the use of an asset, the value of the transaction shall be the higher of fully distributed cost or market price. Market price shall be either the price charged by the utility or if this condition cannot be met, the lowest price charged by another person in the market for the sale or use of a comparable asset, when such prices are publicly available.
- (e) For cost assignment and allocation purposes, the value of all transactions from a non-regulated activity to the utility shall be determined as follows:
- (I) if the transaction involves a product or service that is not provided pursuant to a tariff, the value of the transaction shall be the lower of the fully distributed cost or the market price except if the transaction results from a competitive solicitation process then the value of the transaction shall be the winning bid price. Fully distributed cost in this circumstance, shall be the cost that would be incurred by the utility to provide the service internally. Market price shall be either the price charged by the supplying non-regulated activity or if that condition is not met, the lowest price charged by other persons in the market for a comparable product or service, when such prices are publicly available; or
  - (II) if the transaction involves the sale of an asset, the value of the transaction shall be the lower of net-book cost or market price. If the transaction involves the use of an asset, the value of the transaction shall be at the lower of fully distributed cost or market price. Market price shall be either the price charged by the non-regulated activity or, if this condition cannot be met, the lowest price charged by another person in the market for the sale or use of a comparable asset, where such prices are publicly available.
- (f) If it is impracticable for the utility to establish a market price pursuant to paragraphs (d) or (e), the utility shall provide a statement to that effect, including its reasons in its' fully distributed cost study as well as its proposed method and amount for valuing the transaction. Parties in a Commission proceeding retain the right to advocate alternative market prices pursuant to paragraphs (d) and (e).

- (g) A utility may classify non-jurisdictional services as regulated if the services are rate-regulated by another agency (i.e., another state utility commission or the FERC) and where there are agency-accepted principles or methods for the development of rates associated with such services. This rule may apply, for example, to a provider's wholesale sales of electric power and energy. For such services, the utility shall identify the services in its manual, and account for the revenues, expenses, assets, liabilities, and rate base associated with these services as if these services are regulated.
- (h) For cost assignment and allocation purposes, the value of all transactions between regulated divisions within a utility shall be determined as follows:
  - (I) if the transaction involves a service provided by the utility pursuant to tariff, the value of the transaction shall be at the tariff rate, or
  - (II) if the transaction involves a service or function that is not provided pursuant to a tariff, the value of the transaction shall be at cost.
- (i) If the utility offers a service that is a combination of regulated and non-regulated activities (i.e., a bundled service), the utility shall assign and/or allocate costs to the regulated and non-regulated activities separately.
- (j) A utility may classify incidental activities as regulated activities. If an incidental activity is classified as a regulated activity, the utility shall clearly identify the activity as an incidental activity, and account for the revenues, expenses, assets, liabilities and rate base items as if that activity were a regulated activity.
- (k) To the extent possible, all assigned and allocated costs between regulated and non-regulated activities should have an audit trail which is traceable on the books and records of the applicable regulated utility to the applicable accounts pursuant to the Federal Energy Regulatory Commission Uniform System of Accounts.
- (l) In a rate proceeding involving the calculation of revenue requirements, a complaint proceeding where cost assignments or allocations are at issue, or a proceeding where CAAM approval is sought, the utility or any party may advocate a cost allocation principle other than that already in use, if the Commission has already approved the principle for that cost. The party requesting the alternative approach shall have the burden of proving the need for an alternative principle and why the particular principle is appropriate for the particular cost.

**4503. Cost Assignment and Allocation Manuals.**

- (a) Each utility shall maintain on file with the Commission an approved indexed cost assignment and allocation manual which describes and explains the calculation methods the utility uses to segregate and account for revenues, expenses, assets, liabilities, and rate base cost components assigned or allocated to Colorado jurisdictional activities. It includes the calculation methods to segregate and account for costs between and among jurisdictions, between regulated and non-regulated activities, and between and among utility divisions.
- (b) Each utility shall include the following information in its CAAM.



- (I) A listing of all regulated or non-regulated divisions of the Colorado utility together with an identification of the regulated or non-regulated activities conducted by each.
  - (II) A listing of all regulated or non-regulated affiliates of the Colorado utility together with an identification of which affiliates allocate or assign costs to and from the Colorado utility.
  - (III) A listing and description of each regulated and non-regulated activity offered by the Colorado utility. The Colorado utility shall provide a description in sufficient detail to identify the types of costs associated with the activity and shall identify how the activity is offered to the public and identify whether the Colorado utility provides the activity in more than one state. If an activity is offered subject to tariff, the Colorado utility may identify the tariff and the tariff section that describes the service offering in lieu of providing a service description.
  - (IV) A listing of the revenues, expenses, assets, liabilities and rate base items by Uniform System of Accounts account number that the utility proposes to include in its revenue requirement for Colorado jurisdictional activities including those items that are partially allocated to Colorado as well as those items that are exclusively assigned to Colorado.
  - (V) A detailed description showing how the revenues, expenses, assets, liabilities and rate base items by account and sub-account are assigned and/or allocated to the Colorado utility's non-regulated activities, along with a description of the methods used to perform the assignment and allocations.
  - (VI) A description of each transaction between the Colorado utility and a non-regulated activity which occurred since the Colorado utility's prior CAAM was filed and, for each transaction, a statement as to whether, for this Commission's jurisdictional cost assignment and allocation purposes, the value of the transactions is at cost or market as applicable.
  - (VII) A description of the basis for how the assignment or allocation is made.
  - (VIII) If the utility believes that specific cost assignments or allocations are under the jurisdiction of another authority, the utility shall so state in its CAAM and give a written description of the prescribed methods. Nothing herein shall be construed to be a delegation of this Commission's ratemaking authority related to those assignments or allocations.
  - (IX) Any additional information specifically required by Commission order.
- (c) A utility may treat certain transactions as confidential pursuant to the Commission rules on confidentially.
  - (d) Following the initial approval of its CAAM, the utility shall file an updated CAAM in each rate case proceeding where revenue requirements are determined or every five years following approval of the CAAM then in effect, whichever is earlier.
  - (e) The utility may, at its discretion, file an application seeking Commission approval of updates to its CAAM at any time.

- (f) Whenever a utility files for approval of an update to its CAAM as a result of paragraph (d) or (e) above, the utility shall also simultaneously file a FDC study reflecting the results of the cost allocation methods in its updated manual.
- (g) Each utility shall maintain all records and supporting documentation concerning its CAAMs for so long as such manual is in effect or are subject to a complaint or any active proceeding involving cost allocation before the Commission for as long as such proceeding may be open.

**4504. Fully Distributed Cost Study.**

- (a) The utility shall submit its fully distributed cost study in both electronic and paper format simultaneously with filing its CAAM for all Colorado divisions and activities.
- (b) The utility shall prepare a FDC study that identifies all the non-regulated activities provided by each division in Colorado. The FDC study shall show the revenues, expenses assets, liabilities and rate base items assigned and allocated to each non-regulated activity. If the utility has more than one division (e.g., gas, electric, thermal or non-utility) in Colorado, the FDC study shall include a summary of all assigned and allocated costs by division.
- (c) In preparation of its FDC study, the utility shall complete an analysis of each non-regulated activity to identify the costs that are associated with and/or should be charged to each non-regulated activity to ensure each non-regulated activity is assigned and allocated the appropriate amount of revenues, expenses, assets, liabilities and rate base items.
- (d) If the CAAM is filed in connection with a rate case, the FDC study shall be based on the same test year used in the utility's rate case filing. The utility's FDC study shall include revenues, expenses, assets, liabilities and rate base items in order for the Commission to determine if all appropriate revenues, expenses, assets, liabilities and rate base items have been appropriately assigned and allocated, and to determine the utility's compliance with the principles established in rule 4502. For each assignment and allocation the utility shall:
  - (I) identify the revenues, expenses, assets, liabilities and rate base items by account number, sub-account number and account description; and
  - (II) for each account in (I) above, identify the assignment and allocation method used to assign and allocate costs in sufficient detail to verify the assignment and allocation method used to assign and allocate costs to Colorado divisions and activities is accurate and consistent with the utility's CAAM methodology and reference the CAAM section that describes the allocation; and
  - (III) provide the test year dollar itemized amounts of revenues, expenses, assets, liabilities, and rate base assigned and allocated to each Colorado division and non-regulated activity; the itemized amounts assigned and allocated to the Colorado utility for regulated activities; the itemized amounts assigned and allocated to the Colorado utility for Colorado non-regulated activities; and the itemized amounts assigned and allocated to other jurisdictions.

- (e) Each utility shall maintain all records and supporting documentation concerning its FDC study for so long as such study is in effect or are subject to a complaint or a proceeding before the Commission.

#### **4505. Disclosure of Non-regulated Goods and Services.**

Whenever a Colorado utility engages in the provision or marketing of non-regulated goods or services in Colorado that are not subject to Commission regulation, and the Colorado utility's name or logo is used in connection with the provision of such non-regulated goods and services in Colorado, there must be conspicuous, clear, and concise disclosure to prospective customers that such non-regulated goods and services are not regulated by the Commission. Such disclosure to prospective customers in Colorado shall be included in all Colorado advertising or marketing materials, proposals, contracts, and bills for non-regulated goods and services, regardless of whether the Colorado utility provides such non-regulated goods or services in Colorado directly or through a division or affiliate.

#### **4506. – 4599. [Reserved].**

### **GAS COST ADJUSTMENT AND PRUDENCE REVIEW**

#### **4600. Overview and Purpose.**

Rules 4601 through 4609 are used by LDCs to revise gas rates on an expedited basis. These rules provide instructions for the filing of: gas cost adjustment applications; annual gas purchase plan submittals; and annual gas purchase reports. The purpose of the Gas Cost Adjustment is to enable LDCs, on an expedited basis, to reflect in their rates for gas sales and gas transportation services, as applicable, the increases or decreases in gas costs, including (but not limited to) gas commodity costs and upstream services costs. The purpose of the Gas Purchase Plan is to describe the LDC's plan for purchases of gas commodity and upstream services in order to meet the forecasted demand for sales gas service during each month of the gas purchase year. The purpose of the Gas Purchase Report is to present the LDC's actual purchases of gas commodity and upstream services during each month of the gas purchase year.

#### **4601. Definitions.**

The following definitions apply to rules 4600 through 4609 unless a specific statute or rule provides otherwise. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- (a) "Account No. 191" means an account under the Federal Energy Regulatory Commission System of Accounts used to accumulate actual under-or-over recovered gas supply costs.
- (b) "Base gas cost" means a rate component which is expressed in at least the accuracy of one mil (\$0.001) per Mcf or Dth which reflects the cost of gas commodity and upstream services, when applicable, included in the utility's base rates for sales gas and gas transportation service.
- (c) "Base rates" means the utility's currently-effective rates for sales gas and gas transportation service as authorized by the Commission in the utility's last general rate case.

- (d) "Current gas cost" means a rate component of the GCA which is expressed in at least the accuracy of one mil (\$0.001) per Mcf or Dth and which reflects the cost of gas commodity and upstream service projected to be incurred by the utility during the GCA effective period.
- (e) "Deferred gas cost" means a rate component of the GCA which is expressed in at least the accuracy of one mil (\$0.001) per Mcf or Dth and which is designed to amortize over the GCA effective period the under- or over-recovered gas costs reflected in the utility's Account No. 191 or other appropriate costs for a defined period such as a gas purchase year.
- (f) "Forecasted design peak day quantity" means the total quantity of gas commodity anticipated to be required to meet firm sales and firm gas transportation service demand on the utility's system on a design or historical peak day.
- (g) "Forecasted gas commodity cost" means the cost of gas commodity, including appropriate adjustments for storage gas injections and withdrawals and for exchange gas imbalances, which is projected to be incurred by the utility during the GCA effective period and which is determined by using forecasted gas purchase quantity and forecasted purchase prices.
- (h) "Forecasted gas purchase quantity" means the quantity of gas commodity the utility anticipates it will purchase during the GCA effective period, based upon the forecasted sales gas quantity, adjusted for system gas loss, use, or other anticipated variances.
- (i) "Forecasted purchase prices" means index prices, fixed prices, or other gas contracting price options used in the calculation of the forecasted gas commodity cost.
- (j) "Forecasted sales gas quantity" means the quantity of gas commodity projected to be sold by the utility during the GCA effective period, based upon the normalized quantity of gas commodity sales, adjusted for anticipated changes.
- (k) "Forecasted upstream service cost" means the total cost of upstream services projected to be incurred by the utility during the GCA effective period.
- (l) "Gas commodity throughput" means the amount of gas commodity flowing through the utility's jurisdictional gas facilities during a defined period of time.
- (m) "Gas cost adjustment" or "GCA" means the tariff mechanism by which a gas rate is adjusted to reflect increases or decreases in gas costs.
- (n) "GCA effective period" means the period of time that the GCA rate change is intended to be in effect before being superseded on the effective date of the next scheduled GCA.
- (o) "Gas purchase plan" (GPP) means a submittal pursuant to rule 4605 that describes the utility's planned purchases of gas commodity and upstream services to be used to meet sales gas demand during the gas purchase year.
- (p) "Gas purchase report" (GPR) means a report pursuant to rule 4607 which is filed with the Commission and which describes the utility's actual purchases of gas commodity and upstream services in order to meet sales gas demand during the gas purchase year.

- (q) "Gas purchase year" means a 12-month period from July 1 through June 30.
- (r) "Gas transportation service" means the delivery of gas commodity on the utility's pipeline system (either transmission or distribution) pursuant to any of the utility's gas transportation rate schedules on file with the Commission.
- (s) "Index price" means a published figure identifying a representative price of natural gas commodity available in a geographic area or at specific gas purchasing points during a specified time interval (i.e., daily, weekly, or monthly).
- (t) "Mil" means one-tenth of one cent (\$0.001).
- (u) "Normalized" means the process of adjusting gas quantities to reflect normal historic temperature based on National Oceanic and Atmospheric Administration data or other data as appropriate.
- (v) "Peak day" means a defined period (such as a 24 hour period or a three consecutive coincidental or non-coincidental day average), not less than 24 hours, during which gas commodity throughput is at its maximum level on the utility's system.
- (w) "Receipt point/area" means the point or group of points in a discrete geographic area, such as a supply basin, hub, or market area, at which the utility acquires title to the gas commodity purchased.
- (x) "Sales gas service" means the regulated sale of gas commodity by the utility to customers on the utility's jurisdictional gas system.
- (y) "Service level" means the type or level (whether base, swing, or peak) of gas supply service contracted for by the utility based upon the respective obligations of the supplier to deliver and sell, and the utility to take and purchase, gas commodity.
- (z) "Upstream services" means all transmission, gathering, compression, balancing, treating, processing, storage, and like services performed by others under contract with the utility for the purpose of effectuating delivery of gas commodity to the utility's jurisdictional gas facilities.

**4602. Schedule for Filings by Utilities.**

Utilities subject to rules 4600 through 4609 shall make the required filings in accordance with the following schedule:

- (a) October 1 filing schedule. Public Service Company of Colorado, and Atmos Energy Corporation, shall file with the Commission annual GCA applications with an effective date of October 1. Additional GCA applications may also be filed as necessary pursuant to paragraph 4603(c). The GPR for the preceding gas purchase year in which a GPP was filed shall be filed as a separate filing at the same time as the annual GCA application to be effective October 1.
- (b) November 1 filing schedule. Black Hills/Colorado Gas Utility Company, LP; Black Hills Gas Distribution, LLC; Durango Mountain Utilities; and Colorado Natural Gas, Inc. shall file with the Commission annual GCA applications with an effective date of November 1. Additional GCA applications may also be filed as necessary pursuant to paragraph 4603(c). The GPR for the

preceding gas purchase year in which a GPP was filed shall be filed as a separate filing at the same time as the annual GCA application to be effective November 1.

- (c) All utilities shall file their GPP submittal annually on or before June 1 for the next gas purchase year beginning July 1.

**4603. Gas Cost Adjustments.**

- (a) A utility shall file an application to adjust its GCA. The GCA application shall be filed pursuant to the schedule provided in rule 4602. A utility shall file a GCA application not less than two weeks in advance of the proposed effective date.
- (b) A GCA application shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) the information required by paragraphs 4002(b) and 4002(c); and
  - (II) the information required by rule 4604. Attachments 2, 3, 5 and 6 listed in rule 4604 shall be provided in written form and shall be provided electronically, in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by the Commission staff.
- (c) If the projected gas costs have changed from those used to calculate the currently effective gas cost or if a utility's deferred gas cost balance increases or decreases sufficiently, the utility may file an application to revise its currently effective GCA to reflect such changes, provided that the resulting change to the GCA equates to at least one cent (\$0.01) per Mcf or Dth.
- (d) Applicability of the GCA. The GCA shall be applied to all utility sales gas rate schedules. A utility engaged in the provision of gas transportation service may calculate a GCA that may be applied to transportation gas rate schedules in order to reflect appropriate costs. Absent a Commission decision, a utility engaged in the provision of gas transportation service shall not be required to calculate a transportation GCA factor.
- (e) Interest on under- or over-recovery. The amount of net interest accrued on the average monthly balance in Account No. 191 (whether positive or negative), is determined by multiplying the monthly balance by an interest rate equal to the Commission-authorized customer deposit rate for gas utilities. If net interest is positive, it will be excluded from the calculation of the deferred gas cost.
- (f) Price volatility risk management costs (hedging). Costs related to gas price volatility risk management for jurisdictional gas supply may be included for recovery through the GCA, if allowed by tariffs or by Commission decision. Such costs are subject to the prudence review and standard provided in rule 4607.
- (g) Calculation of the GCA. The GCA shall be calculated to at least the accuracy of one mil per Mcf or Dth pursuant to the following formula, subject to individual GCA rule variances granted by the Commission:

$$\text{GCA} = (\text{current gas cost} + \text{deferred gas cost}) - (\text{base gas cost}).$$

**4604. Contents of GCA Applications.**

- (a) A GCA application shall meet the following requirements.
- (I) Every application shall contain attachments 1 through 9. Attachments 10 through 12 shall be filed with the annual GCA application. The attachments shall meet the requirements set out in this rule.
  - (II) The attachments shall be organized in a manner that specifically references, and responds to, the requirements contained in each subparagraph of this rule.
  - (III) Cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment shall be submitted and provided to Commission staff at the same time as the application.
  - (IV) The application shall cross-reference the proceeding numbers of the associated GPP submittals.
  - (V) When preparing attachments 10 through 12, the rate base, net operating earnings, capital structure, and cost of capital shall be calculated in conformance with the regulatory principles authorized by the Commission in the utility's most recent general rate case, including all required pro forma adjustments.
  - (VI) An explanation of all pro forma adjustments shall be provided.
- (b) GCA attachment No. 1 - GCA Summary. This attachment shall clearly illustrate all of the following principles.
- (I) The impact the utility's currently effective GCA has on each sales gas customer class and, when applicable, the gas transportation rate class on a total dollar and mil (\$0.001, minimum) per Mcf or Dth basis.
  - (II) The impact the utility's proposed GCA has on each sales gas customer class and, when applicable, gas transportation rate class on a total dollar and mil (\$0.001, minimum) per Mcf or Dth basis; and
  - (III) The percent change in total bill for a customer of average usage for each sales gas customer class. This percent change in total bill calculation shall include an itemization of the monthly service and facility charge, base rates and GCA commodity components, and all other tariff charges on the customer bill.
- (c) GCA attachment No. 2 - Current Gas Cost Calculation. This attachment shall contain the calculation of the current gas cost and shall provide month-by-month information with respect to the forecasted gas commodity cost, forecasted gas purchase quantity, forecasted market prices, forecasted upstream service cost, and forecasted sales gas quantity.
- (I) The utility shall calculate current gas cost at least to the accuracy of the nearest mil (\$0.001) per Mcf or Dth according to the following formula, subject to individual GCA rule variances granted by the Commission:

current gas cost = (forecasted gas commodity cost + forecasted upstream service cost) /  
forecasted sales gas quantity.

- (II) The utility shall present all such information in a format comparable with, and corresponding to, the information forecasted in the utility's GPP submittal for each month of the GCA effective period, as required pursuant to rule 4606.
- (d) GCA attachment No. 3 - Deferred Gas Cost Calculation. This attachment shall contain the details of the utility's actual gas purchase costs and the calculation of deferred gas cost. In addition, this attachment shall provide month-by-month information detailing the activity in USOA Account No. 191 by subaccount and period as applicable, interest on under- or over-recovery, and all other included gas costs authorized for recovery in the GCA. The utility shall calculate deferred gas cost as the aggregate total of the under- or over-recovered gas costs reflected in its Account No. 191, or other approved gas costs, recorded at the close of business for each month of the period at issue (such as the previous gas purchase year), plus interest on under- or over-recovery (if net amount is negative), divided by forecasted sales gas quantity. The utility shall calculate deferred gas cost at least to the accuracy of the nearest mil per Mcf or Dth. Each cost a utility includes in the deferred gas cost calculation shall be itemized and clearly identified and itemized for applicability to the period at issue. In its annual GCA applications the utility shall reflect actual deferred costs for the most recent period ending June 30, or as otherwise approved by the Commission.
- (e) GCA attachment No. 4 - Current Tariff. This attachment shall contain the tariff pages which illustrate the gas cost components of the utility's currently-effective rates for sales gas service and, where applicable, gas transportation service.
- (f) GCA attachment No. 5 - Forecasted Gas Transportation Demand. This attachment applies only to utilities that have a GCA component within their authorized rates for gas transportation service. This attachment shall provide the following information, with all demand forecast information provided on a Mcf or Dth basis:
- (I) a forecast of gas commodity throughput attributable to gas transportation service for each month of the GCA effective period; and
  - (II) a forecast of firm backup supply demand quantities (to the extent the utility has such service) under the utility's firm gas transportation service agreements for each month of the GCA effective period.
- (g) GCA attachment No. 6 - current gas cost allocations. This attachment shall fully explain and justify the method(s) used to do each of the following:
- (I) allocate the costs associated with the gas commodity and upstream services to each specific sales gas customer class and, where applicable, gas transportation customer rate class; and
  - (II) derive the amount of the GCA applied to each specific sales gas customer class and, where applicable, gas transportation customer rate classes.



- (h) GCA attachment No. 7 - Customer Notice. This attachment shall provide the form of notice to customers and the public concerning the utility's proposed GCA change. In its customer notice for each sales gas customer class, the utility shall include the following:
  - (I) current and proposed GCA rates and percentage change;
  - (II) comparison of the previous gas purchase year's last average annual bill under prior rates and the projected average annual bill under the proposed GCA rates and percentage change in the total bill amount using an average usage amount for each customer class;
  - (III) comparison of the prior year's peak winter month bill under prior rates and the projected peak winter month bill under the proposed GCA rates and percentage change using an average peak winter month usage amount for each customer class; and
  - (IV) with the annual GCA application, a statement that the utility made a separate gas purchase report filing in accordance with rule 4607 to begin the initial prudence review evaluation process for the prior gas purchase year.
- (i) GCA attachment No. 8 - components of delivered gas cost. This attachment shall detail the itemized rate components of delivered gas cost to the customer (rate), per rule 4406.
- (j) GCA attachment No. 9 - proposed tariff. This attachment shall contain the tariff sheets proposed by the utility to reflect the proposed GCA change.
- (k) GCA attachment No. 10 - rate base. This attachment shall calculate the used and useful rate base assets employed by the utility for Commission-regulated gas operations for the most recently completed 12-month period ending June 30.
- (l) GCA attachment No. 11 - net operating earnings. This attachment shall calculate the utility's net operating earnings for jurisdictional gas operations during the most recently completed 12-month period ending June 30.
- (m) GCA attachment No. 12 - capital structure and cost of capital. This attachment shall calculate the following information for the most recently completed 12-month period ending June 30, the utility's:
  - (I) capital structure for jurisdictional gas operations;
  - (II) cost of long-term debt and preferred equity;
  - (III) cost of common equity; and
  - (IV) weighted average cost of capital.

**4605. Gas Purchase Plans.**

- (a) GPP filing requirements. The utility shall file its GPP as a "Submittal for Determination of Completeness of GPP." This submittal shall include the following proceeding caption: "In the

matter of Gas Purchase Plans and Gas Purchase Reports for [utility] for the Gas Purchase Year from July 1, [year] through June 30, [year]."

- (b) Contents of GPP filing. In the GPP, the utility shall submit to the Commission the following:
  - (I) the information required by rule 4606;
  - (II) the utility's forecasted quantity of gas to be purchased over the ensuing gas purchase year for each service level;
  - (III) the utility's forecasted pricing for each receipt point/area; and
  - (IV) the utility's portfolio management plan.
- (c) Commission procedures for processing filings. Upon receipt of a GPP submittal, the Commission shall assign a proceeding number and shall review the submittal solely for completeness (i.e., compliance with the information requirements of these rules). The Commission shall not: hold a hearing on the substance of the GPP, entertain interventions by interested parties, require the filing of testimony or permit discovery. The Commission shall not render a decision approving or disapproving the substantive information contained in the submittal.
- (d) Review timelines. Commission staff shall review the submittal and, within 15 calendar days of the filing, shall provide written notification to the utility of any deficiencies in the submittal. The utility shall file the requested information, or a written statement indicating that the utility believes the additional information is not required, within 15 calendar days after the date of the Commission staff notification. Upon receipt of final information or the written statement, Commission staff shall place the submittal on the agenda for consideration at the next available Commissioners' weekly meeting. If the Commission fails to mail its determination on completeness of the submittal within 15 calendar days of receipt of final information or the written statement, the submittal shall be deemed complete.
- (e) Utilities with multiple GCA rate areas. A utility with more than one approved GCA rate area in Colorado shall file a separate GPP for each GCA rate area. These GPPs may be filed in a single submittal.
- (f) GPP no longer reflects market conditions. A utility shall file a new GPP within 30 days of its determination that the currently effective GPP no longer substantively reflects active purchasing conditions or the utility's planned purchasing practices.

**4606. Contents of the GPP.**

A GPP submittal shall contain the following attachments. The utility shall organize attachments in a manner that specifically references, and responds to, the requirements of paragraphs (a) through (d) of this rule. With its submittal, the utility shall provide cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment.

- (a) GPP attachment No. 1 - gas purchase schedule. This attachment shall provide a forecast of the specific gas commodity supplies, segregated by receipt point/area, which the utility plans to

purchase in order to meet forecasted sales gas demand during each month of the applicable gas purchase year.

- (b) GPP attachment No. 2 – gas purchasing pricing description. For each specific receipt point/area, this attachment shall provide an estimate of applicable ranges of forecast index prices expected to be incurred, short-term fixed prices (one-year or other appropriate term), and other relevant pricing options, as applicable to the portfolio management plan described in GPP attachment 3.
- (c) GPP attachment No. 3 – portfolio management plan. This attachment shall provide a plan stating how the utility plans to manage its gas supply portfolio for the gas purchase year. This attachment shall also include a description and analysis of the options the utility considered, or will consider, and the steps the utility has taken, or will take, to reduce customers' risk of gas price volatility for the gas purchase year. To the extent a utility proposes to use gas price volatility risk management tools, this attachment shall include a description of the utility's policy for implementing such risk management tools, including a projection of such costs and the assumptions underlying all cost estimates.
- (d) GPP attachment No. 4 - forecasted upstream service costs. This attachment shall include the following information for each month of the applicable gas purchase year:
  - (I) An itemized list of all upstream services, by provider and service level or rate schedule, and associated costs, that the utility expects to purchase in the upcoming gas purchase year in order to meet sales gas and gas transportation demand .
  - (II) A comparison of forecasted design peak day delivery quantity with all sources of capacity available to the utility, including forecasted upstream services, forecasted gas commodity to be purchased directly into the utility's distribution system (i.e., city gate purchases) on a firm basis, and the utility's own gas storage facilities or purchased gas storage capacity.
  - (III) A comprehensive explanation of the utility's forecasted level of planned upstream service purchases.
  - (IV) Forecasted capacity release volumes and revenues for release of upstream capacity by the utility.

**4607. Gas Purchase Reports and Prudence Reviews.**

- (a) GPR filing requirements. The utility shall file a GPR under the previous year's GPP proceeding number (filed approximately 15 months previously) as a separate filing from, and at the same time as, the annual GCA application. Specific attachments or other information may be filed under seal; however, an explanation of the confidential nature of the attachments or information must be included in the GPR filing.
- (b) Prudence review process. Based on the initial evaluation of the GPR, the Commission may initiate a prudence review hearing. The Commission shall initiate this hearing by written order within 120 days of the filing of the GPR. The prudence review may result in tariff or rate changes that could affect different classifications of customers.

- (c) Prudence review standard. For purposes of GCA recovery, the standard of review to be used in assessing the utility's action (or lack of action) in a specific gas purchase year is: whether the action (or lack of action) of a utility was reasonable in light of the information known, or which should have been known, at the time of the action (or lack of action).
- (d) Burden of proof. If the Commission elects to hold a hearing, the utility shall have the burden of proof and the burden of going forward to establish the reasonableness of actual gas commodity and demand costs paid by the utility, actual costs incurred in volatility management, and actual upstream service costs of any nature incurred during the review period.
- (e) Utility testimony and attachments. If the Commission sets a hearing, the utility shall file its testimony supporting gas cost recovery for the gas purchase year at issue. The testimony shall be filed in question-and-answer format. The utility shall file its testimony not later than 45 days after the Commission sets the matter for hearing.

**4608. Contents of the GPR.**

A GPR shall contain the following attachments. The utility shall organize the attachments in a manner that specifically references, and responds to, paragraphs (a) through (d) of this rule. The utility shall also present all such information in a format comparable with, and corresponding to, the information forecasted in the utility's GPP submittal as required pursuant to rule 4606 and GCA application pursuant to rule 4604. The utility shall provide an explanation of, and justification for, any material deviations from its GPP. All underlying support documentation and work papers shall be made available. With its filing, the utility shall provide cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment.

- (a) GPR attachment No. 1 - actual gas commodity purchases. This attachment shall provide, in a format comparable to the information provided in GPP attachment 1, the quantities of, and actual invoice costs of, specific gas commodity supplies, segregated by receipt point/area that the utility purchased in order to meet actual sales gas and gas transportation demand during the peak day and for each month of the gas purchase year.
- (b) GPR attachment No. 2 - description of actual market prices. This attachment shall provide, in a format comparable to the information provided in GPP attachment 2, actual index prices, short-term fixed prices (one-year, or other appropriate term), and other relevant pricing options for each specific receipt point area, as applicable to the portfolio management plan described in GPP and GPR attachments 3.
- (c) GPR attachment No. 3 - actual portfolio purchases. This attachments shall provide, in a format comparable to the information provided in GPP exhibit 3, a comparison of the utility's portfolio management plan and the results actually achieved through the implementation of this plan (or modification thereto), in order to demonstrate, using the standard of review specified in paragraph 4607(c), the prudence of actual portfolio purchases. This attachment shall include a detailed itemization of gas price volatility risk management costs if applicable.
- (d) GPR attachment No. 4 - actual upstream service costs. This attachment shall provide, in a format comparable to the information provided in GPP attachment 4, the following information for each month of the gas purchase year:

- (I) an itemized list of the upstream services the utility actually purchased in order to meet sales gas and gas transportation demand;
- (II) an itemized listing of the specific costs the utility incurred to purchase upstream services;
- (III) actual peak day demand experienced by the utility during the gas purchase year; and
- (IV) an itemized list of capacity release volumes and revenues.

**4609. General Provisions.**

- (a) For each attachment filed by the utility as confidential under rules 4600 through 4609, the utility shall provide, at a minimum, a version of the attachment with publicly available information.
- (b) A utility shall monitor the net under- or over-recovery balance in USOA Account No. 191 on a monthly basis. On a quarterly basis, or as otherwise established individually for a utility, a utility shall file, within 30 days of the end of the quarter, a report to the Commission stating the USOA Account No. 191 balance calculation for each rate area. The reports shall include the USOA Account No. 191 balance information specified in GCA attachment 3 and shall be filed in one common proceeding, established by the Commission to receive USOA Account No. 191 balance filings from all utilities. If the utility identifies a significant net under- or over- recovery balance during the gas purchase year, the utility shall initiate appropriate action to mitigate the significant under- or over- recovery balance.

**4610. – 4699. [Reserved].**

**APPEALS OF LOCAL GOVERNMENT LAND USE DECISIONS**

**4700. Scope and Applicability.**

Rules 4700 through 4707 apply to all utilities or power authorities which seek to appeal a local government action concerning a major natural gas facility.

**4701. Definitions.**

The following definitions apply to rules 4700 through 4707, unless a specific statute or rule provides otherwise. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- (a) "Local government" means a county, a home rule or statutory city, a town, a territorial charter city, or a city and county.
- (b) "Local government action" means (1) any decision, in whole or in part, by a local government which has the effect or result of denying a permit or application of a utility that relates to the location, construction, or improvement of a major natural gas facility or (2) a decision imposing requirements or conditions upon such permit or application that will unreasonably impair the ability of the utility to provide safe, reliable, and economical service to the public.

- (c) "Local land use decision" means the decision of a local government within its jurisdiction to plan for and regulate the use of land.
- (d) "Major natural gas facility" is defined by § 29-20-108(3)(e), C.R.S., or by any other applicable statute.
- (e) "Power authority" means an authority created pursuant to § 29-1-204, C.R.S.

**4702. Precondition to Application.**

In order for a utility or power authority to appeal a local government action to the Commission pursuant to this rule and pursuant to § 29-20-108, C.R.S., one or more of the following conditions must be met:

- (a) the utility or power authority has applied for or has obtained a certificate of public convenience and necessity from the Commission pursuant to § 40-5-101, C.R.S., to construct the major natural gas facility that is the subject of the local government action;
- (b) a certificate of public convenience and necessity is not required for the utility or power authority to construct the major natural gas facility that is the subject of the local government action; and
- (c) the Commission has previously entered an order pursuant to § 40-4-102, C.R.S., that conflicts with the local government action.

**4703. Applications.**

- (a) To commence an appeal of a local government land use decision, a utility or power authority shall file with the Commission an application pursuant to this rule.
- (b) An application filed in accordance with §§ 29-20-108, C.R.S., and this rule shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) all of information required in paragraphs 4002(b) and 4002(c);
  - (II) a showing that one of the preconditions set out in rule 4702 has been met;
  - (III) identification of the major natural gas facility;
  - (IV) identification of the local government action and its impact on the major natural gas facility;
  - (V) a statement of the reasons the applying utility or power authority believes that the local government action would unreasonably impair its ability to provide safe, reliable, and economical service to the public;
  - (VI) the demonstrated need for the major natural gas facility or reference to the application made to the Commission with respect to the major natural gas facility and the resulting decision of the Commission regarding such facility;

- (VII) the extent to which the proposed facility is inconsistent with existing applicable local or regional land use ordinances, resolutions, or master or comprehensive plans;
- (VIII) whether the proposed facility would exacerbate a natural hazard;
- (IX) applicable utility engineering standards, including supply adequacy, system reliability, and public safety standards;
- (X) the relative merit, as determined through use of the normal system planning evaluation techniques of the utility or power authority, of any reasonably available and economically feasible alternatives proposed by the utility, the power authority, or the local government;
- (XI) the impact that the local government action would have on the customers of the utility or power authority who reside within and without the boundaries of the jurisdiction of the local government;
- (XII) the basis for the local government action. If available, the utility or power authority shall attach a copy of the local government action;
- (XIII) the impact the proposed facility would have on residents within the local government's jurisdiction including, in the case of a right-of-way in which facilities have been placed underground, whether those residents have already paid to place such facilities underground. If the residents have already paid to place facilities underground, the Commission will give strong consideration to that fact;
- (XIV) information concerning how the proposed major natural gas facility will affect the safety of residents within and without the boundaries of the jurisdiction of the local government; and
- (XV) an attestation that the utility or power authority will, upon filing the application with the Commission, simultaneously send the application to the local government body which took the local government action which is the subject of the appeal.

**4704. Public Hearing.**

In addition to the formal evidentiary hearing on the appeal, and pursuant to § 29-20-108(5)(b), C.R.S., the Commission shall take statements from the public concerning the appealed local government action at a public hearing held at a location specified by the local government.

**4705. Prehearing Conference, Parties, and Public Notice.**

- (a) In order to assist the parties in scheduling the public hearing, determining the scheduling of the evidentiary hearing, developing the list of persons to receive notice of these hearings, and addressing other pertinent issues, the Commission will hold a prehearing conference.
- (b) The Commission shall conduct a prehearing conference within 15 days after the application is deemed complete by the Commission.

- (c) The Commission shall join as an indispensable party the local government which took the contested local government action.
- (d) Ten days before the commencement of the prehearing conference, the local government shall submit to the parties and the Commission its preference for the location of the public hearing to be held in accordance with § 29-20-108(5)(b), C.R.S., and rule 4704.
- (e) The Commission will decide the date and time of the public hearing after receiving comments from the parties at the prehearing conference.
- (f) By the date of the prehearing conference, each party shall provide to the utility a list of individuals and groups to receive notice of the public hearing.
- (g) The utility or power authority shall give notice of the public hearing to the identified individuals and groups in a manner specified by the Commission. Notice may be accomplished by newspaper publication, bill insert, first class mail, or any other manner deemed appropriate by the Commission.
- (h) If the local government is unable to provide meeting space for the public hearing, and space needs to be acquired, then the utility or power authority shall bear any cost associated with the rental of such space for the public hearing.
- (i) The parties are encouraged to confer prior to the prehearing conference to develop a schedule for the filing of testimony and the dates for the formal evidentiary hearing.

**4706. Denial of Appeal.**

In accordance with § 29-20-108(5)(e), C.R.S., the Commission shall deny an appeal of a local government action if the utility or power authority has failed to comply with the following notification and consultation requirements:

- (a) A utility or power authority shall notify the affected local government of its plans to site a major natural gas facility within the jurisdiction of the local government prior to submitting the preliminary or final permit application, but in no event later than filing a request for a certificate of public convenience and necessity pursuant to Article 5 of Title 40, C.R.S., or the filing of any annual filing with the Commission that proposes or recognizes the need for construction of a new major natural gas facility or the extension of an existing facility. If a utility or power authority is not required to obtain a certificate of public convenience and necessity pursuant to Article 5 of Title 40, C.R.S., or to file annually with the Commission to notify the Commission of proposed construction of a new major natural gas facility or the extension of an existing facility, then the utility or power authority shall notify any affected local governments of its intention to site a new major natural gas facility within the jurisdiction of the local government when such utility or power authority determines that it intends to proceed to permit and to construct the facility. Following such notification, the utility or power authority shall consult with the affected local governments in order to identify the specific routes or geographic locations under consideration for the site of the major natural gas facility and to attempt to resolve land use issues that may arise from the contemplated permit application.



- (b) In addition to its preferred alternative within its permit application, the utility or power authority shall consider and present reasonable siting and design alternatives to the local government or shall explain why no reasonable alternatives are available.

**4707. Procedural Rules.**

Pursuant to § 29-20-108(5)(b), C.R.S., any appeal brought by a utility or power authority under this section shall be conducted in accordance with the procedural requirements of Article 6, Title 40, C.R.S., including § 40-6-109.5, C.R.S. Evidentiary hearings on any such appeals shall be conducted in accordance with § 40-6-109, C.R.S.

**4708. – 4749. [Reserved].**

**DEMAND SIDE MANAGEMENT**

**4750. Overview and Purpose.**

These rules implement §§ 40-1-102, 40-3.2-101, 40-3.2-103, and 40-3.2-105, C.R.S. for LDCs required by statute to be rate-regulated. Consistent with statutory requirements, the purpose of these Demand Side Management (DSM) rules is to reduce end-use natural gas consumption in a cost effective manner, in order to save money for consumers and utilities, and protect the environment by encouraging the reduction of emissions and air pollutants. These rules direct natural gas utilities in the design and implementation of programs that will enable sales customers to participate in DSM. The LDC shall design DSM programs for its full service customers to achieve cost-effective energy savings, considering factors such as: achievable energy savings, customer benefits, cost effectiveness ratios, adoption potential, market transformation capability and ability to replicate in the utility service territory.

- (a) Each utility shall file an application for approval of a DSM plan within the parameters set forth in these rules. In the application, the utility shall include a proposed expenditure target, savings target, funding mechanism, and cost-recovery mechanism.
- (b) Each utility shall annually file an advice letter or application for cost recovery, as permitted herein.
- (c) Each utility shall annually file a DSM report. The DSM report shall include the results of any measurement and verification (M&V) evaluation conducted during the DSM report period.

**4751. Definitions.**

The following definitions apply to rules 4750 through 4760, unless § 40-1-102 provides otherwise.

- (a) “Amortization” means the systematic spreading of expenditures or capital costs incurred for DSM programs, through regular accounting entries over a specified period of time.
- (b) “Benefit/cost ratio” means the ratio of the net present value of benefits to the net present value of costs, as calculated using the modified TRC test.
- (c) “Cost effective” means a benefit/cost ratio of greater than one.

- (d) “Demand side management” (DSM) means the implementation of programs or measures which serve to shift or reduce the consumption of, or demand for, natural gas.
- (e) “Discount rate” means the interest rate used in determining the present value of future cash flows of DSM costs and benefits, for both forecasted and actual cash flows. The forecasted DSM costs and benefits are used to estimate the cost effectiveness of DSM measures to develop a cost effective DSM portfolio. The actual DSM costs and benefits, which are the actual costs of the program and the documented energy savings, are used to determine net economic benefits for the purpose of calculating the bonus. Discount rate shall be the utility’s after-tax weighted average cost of capital (WACC).
- (f) “DSM education” means a program, including but not limited to an energy audit, that contributes indirectly to a cost-effective DSM program by promoting customer awareness and participation.
- (g) “DSM measure” means an individual component or technology, such as attic insulation or replacement of equipment.
- (h) “DSM period” means the effective period of an approved DSM plan.
- (i) “DSM plan” means the DSM programs, goals, and budgets over a specified DSM period, generally considered in one year increments, as may be proposed by the utility.
- (j) “DSM program” means any combination of DSM measures, information and services offered to customers to reduce natural gas usage.
- (k) “Energy efficiency program” see DSM program.
- (l) “Gas Demand-Side Management Cost Adjustment” (G-DSMCA) means a rate adjustment mechanism designed to compensate a utility for its DSM program costs.
- (m) “Gas Demand-Side Management bonus” (G-DSM bonus) means a bonus awarded to a utility in accordance with § 40-3.2-103(2)(d), C.R.S.
- (n) “Market transformation” means a strategy for influencing the adoption by consumers of new techniques or technologies. The objective is to overcome barriers within a market through coordinating tactics such as education, training, product demonstration and marketing, often conducted in concert with rebates or other financial incentives.
- (o) “Modified Total Resource Cost test” or “modified TRC test” means an economic cost-effectiveness test used to compare the net present value of the benefits of a DSM program or measure over its useful life, to the net present value of costs of a DSM measure or program for the participant and the utility, consistent with § 40-1-102(5), C.R.S. In performing the modified TRC test, the benefits shall include, but are not limited to, as applicable: the utility’s avoided production, distribution and energy costs; the participant’s avoided operating and maintenance costs; the valuation of avoided emissions; and non-energy benefits as set forth in rule 4753. Costs shall include utility and participant costs. The utility costs shall include the net present value of costs incurred in accordance with the budget set forth in rule 4753.

- (p) “Net economic benefits” means the net present value of all benefits in the modified TRC test, as applied to the utility’s portfolio of DSM programs, less the net present value of the costs in the modified TRC test associated with that same portfolio.
- (q) “Sales customer” or “full service customer” means a residential or commercial customer that purchases a bundled natural gas supply and delivery service from a utility but does not include customers served under a utility’s gas transportation service rate schedules.

**4752. Filing Schedule.**

- (a) Each utility shall implement and maintain its DSM plan and G-DSMCA, as approved by the Commission.
- (b) Each utility shall submit its annual DSM report on or before April 1 of each year.
- (c) Each utility seeking a G-DSM bonus shall file an application pursuant to rule 4760 requesting approval of such bonus on or before April 1 of each year.
- (d) Each utility shall file an advice letter on or before May 31 of each year to adjust the G-DSMCA to be effective July 1 for a period of 12 months. Alternatively, each utility may file a combined application on or before April 1 of each year seeking a G-DSM bonus, as well as an adjustment to the G-DSMCA, to be effective July 1 for a period of 12 months.
- (e) By May 1 of the final year of the currently effective DSM plan, each utility shall file by application a prospective natural gas DSM plan for Commission approval.

**4753. Periodic DSM Plan Filing.**

Each utility shall periodically file, in accordance with paragraph 4752(e), a prospective natural gas DSM plan that covers a DSM period of three years, unless otherwise ordered by the Commission. The plan shall include the following information:

- (a) the utility’s proposed expenditures by year for each DSM program, by budget category; the sum of these expenditures represents the utility’s proposed expenditure target as required by § 40-3.2-103(2)(a), C.R.S.;
- (b) the utility’s estimated natural gas energy savings over the lifetimes of the measures implemented in a given annual DSM program period, expressed in dekatherms per dollar of expenditure, and presented for each DSM program proposed for Commission approval; this represents the utility’s proposed savings target required by § 40-3.2-103(2)(b), C.R.S.;
- (c) the anticipated units of energy to be saved annually by a given annual DSM program, which equals the product of the proposed expenditure target and proposed savings target; this product is referred to herein as the energy target;
- (d) the estimated dollar per therm value that represents the utility’s annual fixed costs that are recovered through commodity sales on a per therm basis;

- (e) the utility shall include in its DSM plan application data and information sufficient to describe the design, implementation, oversight and cost effectiveness of the DSM programs. Such data and information shall include, at a minimum, program budgets delineated by year, estimated participation rates and program savings (in therms);
- (f) in the information and data provided in a proposed DSM plan, the utility shall reflect consideration of the factors set forth in the Overview and Purpose, rule 4750. At a minimum the utility shall provide the following information detailing how it developed its proposed DSM program:
  - (I) descriptions of identifiable market segments, with respect to gas usage and unique characteristics;
  - (II) a comprehensive list of DSM measures that the utility is proposing for inclusion in its DSM plan;
  - (III) a detailed analysis of proposed DSM programs for a utility's service territory in terms of markets, customer classes, anticipated participation rates (as a number and a percent of the market), estimated energy savings and cost effectiveness;
  - (IV) a ranking of proposed DSM programs, from greatest value and potential to least, based upon the data required in subparagraph (f)(III);
  - (V) proposed marketing strategies to promote participation based on industry best practices;
  - (VI) calculation of cost effectiveness of the proposed DSM programs using a modified TRC test. Each proposed DSM program is to have a projected value greater than or equal to 1.0 using a modified TRC test, except as provided for in paragraph 4753 (g);and
  - (VII) an analysis of the impact of the proposed DSM program expenditures on utility rates, assuming a 12-month cost recovery period.
- (g) In its DSM plan, the utility shall address how it proposes to target DSM services to low-income customers. The utility shall also address whether it proposes to provide DSM services directly or indirectly through financial support of conservation programs for low-income households administered by the State of Colorado, as authorized by § 40-3.2-103(3)(a), C.R.S. The utility may propose one or more low-income DSM programs that yield a modified TRC test value below 1.0.
- (h) In proposing an expenditure target for Commission approval, pursuant to § 40-3.2-103 (2)(a), C.R.S., the utility shall comply with the following:
  - (I) the utility's annual expenditure target for DSM programs shall be, at a minimum, two percent of a natural gas utility's base rate revenues, (exclusive of commodity costs), from its sales customers in the 12-month calendar period prior to setting the targets, or one-half of one percent of total revenues from its sales customers in the 12-month calendar period prior to setting the targets, whichever is greater;
  - (II) the utility may propose an expenditure target in excess of two percent of base rate revenues; and

- (III) funds spent for education programs, market transformation programs and impact and process evaluations and program planning related to natural gas DSM programs may be recovered without having to show that such expenditures, on an independent basis, are cost-effective; such costs shall be included in the overall benefit/cost ratio analysis.
- (i) The utility shall propose a budget to achieve the expenditure target proposed in paragraph 4753 (a). The budget shall be detailed for the overall DSM plan and for each program for each year and shall be categorized into:
  - (I) planning and design costs;
  - (II) administrative and DSM program delivery costs;
  - (III) advertising and promotional costs, including DSM education;
  - (IV) customer incentive costs;
  - (V) equipment and installation costs;
  - (VI) measurement and verification costs; and
  - (VII) miscellaneous costs.
- (j) The budget shall explain anticipated increases/decreases in financial resources and human resources from year to year.
- (k) A utility may spend more than the annual expenditure target established by the Commission up to 25 percent over the target, without being required to submit a proposed DSM plan amendment. A utility may submit a proposed DSM plan amendment for approval when expenditures are in excess of 25 percent over the expenditure target.
- (l) As a part of its DSM plan, each utility shall propose a DSM plan with a benefit/cost value of unity (1) or greater, using a modified TRC test.
- (m) For the purposes of calculating a modified TRC, the non-energy benefits of avoided emissions and societal impacts shall be incorporated as follows.
  - (I) The initial TRC ratio, which excludes consideration of avoided emissions and other societal benefits, shall be multiplied by 1.05 to reflect the value of the avoided emissions and other societal benefits. The result shall be the modified TRC. A utility may propose for approval a different factor for avoided emissions and societal impacts, but must submit documentation substantiating the proposed value.
- (n) Measurement and verification (M & V) plan. The utility shall describe in complete detail how it proposes to monitor and evaluate the implementation of its proposed programs. The utility shall explain how it will accumulate and validate the information needed to measure the plan's performance against the standards, pursuant to rule 4755. The utility shall propose measurement and verification reporting sufficient to communicate results to the commission in a detailed, accurate and timely basis.

**4754. Annual DSM Report and Application for Bonus and Bonus Calculation.**

On the schedule set forth in rule 4752, the utility shall provide the Commission a detailed DSM report and application for bonus.

- (a) In the annual DSM report, the utility shall describe its actual DSM programs as implemented. For each DSM program, the utility shall document actual program expenditures, energy savings, participation levels and cost-effectiveness.
- (b) Annual program expenditures shall be separated into cost categories contained in the approved DSM plan.
- (c) For each DSM program, the utility shall compare the program's proposed and actual expenditures, savings, participation rate, and cost-effectiveness; in addition, the utility shall prepare an assessment of the success of the program, and list any suggestions for improvement and greater customer involvement.
- (d) The utility shall provide actual benefit/cost results for the overall DSM plan and individual DSM programs implemented during the plan year. The benefit/cost analysis shall be based on the costs incurred and benefits achieved, as identified in the modified TRC test. Benefit values are to be based upon the results of M & V evaluation, when such has been conducted as set forth in rule 4755. Otherwise, the benefit values of the currently approved DSM plan are to be used.
- (e) If the annual report covers a year within which an M & V evaluation was completed, the complete M & V results are to be included as part of the annual report.
- (f) The utility may file an application for bonus, pursuant to rule 4760. The application for bonus shall include the utility's calculation of estimated bonus applying the methodology set forth in this rule to the utility's actual performance.
- (g) The Commission shall determine the level of bonus, if any, that the utility is eligible to collect on the basis of the information included in the report, pursuant to the bonus criteria and process set forth, below.
  - (l) The primary objective of the bonus is to encourage cost-effective energy savings. The amount of bonus earned, if any, will correlate with the utility's performance relative to the approved savings target (dekatherms saved per dollar expended) and the energy target. Assuming all other factors that affect consumption remain unchanged, effective DSM programs will reduce per customer commodity consumption, which may lead to revenue reductions for the utility. The utility may include in the bonus application a request for approval to recover a calculated amount of revenue that acknowledges the DSM program reduced the utility's revenue. The recovery amount for reduced revenue is separate from any bonus determined by the Commission and shall be calculated, as follows:
    - (A) the utility shall calculate a dollar per therm value that represents the utility's annualized fixed costs that are recovered through commodity sales on a per therm basis;

- (B) the utility shall include in the DSM filing pursuant to rule 4753 a proposed dollar per therm value with the calculation methodology and supporting documentation;
  - (C) the recovery amount for reduced revenue shall be calculated by multiplying the dollar per therm value by the annualized number of therms saved and reported in the utility's annual DSM report for the plan year;
  - (D) the recovery of the reduced revenue amount shall be through the Demand-Side Management Cost Adjustment (DSMCA), over the same twelve month period in which any approved bonus amount is recovered, as set forth in subparagraph 4752 (b)(l); and
  - (E) for the purpose of inclusion in the above calculation, the annual report shall include the number of therms projected to be saved from the DSM programs in the twelve months following the end of the program year.
- (II) As a threshold matter, the utility must expend at least the minimum amount set forth in subparagraph 4753 (h)(l), in order to earn a bonus.
- (III) The bonus amount is a percentage of the net economic benefits resulting from the DSM plan over the period under review. The percentage value is the product of the two factors:
- (A) The Energy Factor is determined by the percentage of the energy target achieved by the utility. The energy factor is zero plus 0.5 percent for each one percent above 80 percent of the energy target achieved by the utility.
  - (B) The Savings Factor is the actual savings achieved divided by the approved savings target. The actual savings achieved and approved savings target are each expressed in dekatherms saved per dollar expended.
- (IV) The following is provided as an example of the bonus calculation, using these illustrative numbers: utility achieves 106 percent of its energy target; the utility's savings target is 15,000 dekatherms per \$1 million expended, and the utility's actual savings is 18,000 dekatherms per \$1 million.
- The energy factor would be:  $50 \text{ percent} \times (106 - 80)$ , or 13 percent
- The savings factor would be:  $18,000/15,000$  or 1.2
- The resulting bonus percentage would be:  $13 \text{ percent} \times 1.2$ , or 15.6 percent. Thus, 15.6 percent of net economic benefits would be the bonus amount.
- (h) For the purposes of calculating the bonus, the costs and benefits associated with DSM programs targeted to low-income customers may be excluded as follows:
- (l) the costs and benefits associated with a low-income DSM program may be excluded from the calculation of the net economic benefits for the entire DSM portfolio if the modified TRC value for the low-income program is below 1.0; and

- (II) the expenditures and therms saved associated with a low-income DSM program may be excluded from the calculation of the Savings Factor if the therms saved per dollar expended for the low-income program is below the approved savings target for the overall DSM portfolio.
- (i) The maximum bonus is 20 percent of net economic benefits or 25 percent of expenditures, whichever is less.
- (j) Any awarded bonus shall be authorized as a supplement to a utility and not count against its authorized rate of return or be considered in rate proceedings. The awarded bonus shall be recovered through the G-DSMCA over a 12-month period after approval of the bonus.

**4755. Measurement and Verification.**

- (a) Each utility shall implement a measurement and verification (M & V) program to evaluate the actual performance of its DSM program. The utility shall present its M & V plan as a part of its DSM plan application, pursuant to rule 4753, and shall include the complete M & V evaluation results with its annual DSM report in those years when the M & V is conducted.
- (b) As a part of its M & V program, the utility shall, at a minimum, design a M & V plan to evaluate the effectiveness of the actual DSM measures and programs implemented by the utility. The M & V plan shall address: sampling bias; a data gathering process sufficient to yield statistically significant results; and generally accepted methods of data analysis. The M & V plan shall also include an evaluation of free ridership, spillover and the net-to-gross ratio. The M & V evaluation shall be implemented at least once per the DSM plan period. Subsequent DSM plan applications shall reflect the results of all completed M & V evaluations.
- (c) The M & V evaluation shall, at a minimum, include the following:
  - (I) an assessment of whether the DSM programs have been implemented as set forth in its Commission approved DSM plan;
  - (II) a measurement of the actual energy savings for each DSM program, in dekatherms per dollar expended and in total dollars, and a comparison to the corresponding utility projections in the approved DSM plan;
  - (III) to the extent feasible, an assessment of the period of time that each DSM measure actually remains in service, and a comparison to the corresponding utility projections in the approved DSM plan;
  - (IV) a summary of the actual benefit/cost ratio for each DSM program within the approved DSM plan;
  - (V) an assessment of the extent to which education and market transformation efforts are achieving the desired results; and
  - (VI) recommendations for how the utility can improve the market penetration and cost effectiveness of individual DSM programs.



**4756. General Provisions Concerning Cost Allocation and Recovery.**

- (a) Amortization periods.
  - (I) For the base rate method, the utility shall propose the amortization period. The utility shall specify and explain the rationale for the amortization period proposed for each DSM program as a part of its DSM plan application, filed pursuant to rule 4753.
  - (II) For the expense method, the utility shall recover the annual expenditures projected for that year over a one-year period.
- (b) Fuel switching. Fuel switching from natural gas to other fossil fuel derived energy sources shall not be included in the gas utility's DSM program. Programs to save natural gas through switching to renewable energy sources such as solar heating and ground source heat pumps are allowed.
- (c) A utility that provides both regulated gas and electric service shall give consideration to the administrative benefits and reduced costs associated with combining gas and electric DSM activities and shall assign costs and benefits appropriately to each plan.
- (d) Distribution of DSM program expenses.
  - (I) The utility shall include in its portfolio-level benefit/cost analysis all indirect costs relating to DSM, including but not limited to DSM customer education, program design, and evaluation costs.
  - (II) A utility's existing gas efficiency and conservation customer education tools, such as on-line energy assessment tools or other similar internet based tools, may be included in a utility's gas DSM plan and costs recovered pursuant to the gas DSMCA rule.

**4757. Funding and Cost Recovery Mechanism.**

The purpose of the G-DSMCA is to enable utilities to recover prudently incurred gas DSM program expenses without requiring a change in their base rates for gas sales. All such costs, plus any G-DSM bonus approved by the Commission, shall be recovered through the G-DSMCA that is set on an annual basis, and collected from July 1 through June 30. The G-DSMCA allows for prospective recovery of prudently incurred costs of DSM programs within the DSM program expenditure target approved by the Commission in order to provide for funding of the utility's DSM programs, as well as recovery of deferred G-DSMCA costs, without having to file a rate case.

- (a) A utility may spend a disproportionate share of total expenditures on one or more classes of customers, provided, however, that cost recovery for programs directed at residential customers are to be collected from residential customers only and that cost recovery for programs directed at nonresidential customers are to be collected from nonresidential customers only, except as provided for in paragraph 4757 (f).
- (b) The utility may recover its DSM program expenditures either through expensing or by adding DSM program expenditures to base rates as a part of, or outside of, a rate case, with an amortization period as set forth in rule 4756.

- (c) There shall be no financial penalty assessed on a utility for failing to reach its approved DSM program expenditure target, nor shall there be a bonus simply for meeting its DSM program expenditure target. All prudently incurred expenditures for the utility's portfolio of DSM programs are recoverable. However, the portion of costs yielding a modified TRC test value below 1.0 loses its presumption of prudence and is subject to review.
- (d) Amounts not spent under the DSM program expenditure target shall not roll-over to the next DSM period.
- (e) A utility has the discretion and the responsibility of managing the portfolio of DSM programs to meet the benefit to cost ratio and the energy and savings targets. In implementing DSM programs, a utility shall use reasonable efforts to maximize energy savings consistent with the approved DSM plan.
- (f) A utility may continue DSM programs that were in existence on or before May 22, 2007, the effective date of § 40-3.2-103, C.R.S., concerning measures to promote energy efficiency, and shall not be required to obtain approval from the Commission for recovery of costs associated with such programs. Any new expenditure for such programs must be included in the annual DSM plan filing and G-DSMCA application. Existing low-income DSM programs that recover costs from all customer classes shall continue such recovery.
- (g) A utility shall file a request to adjust its G-DSMCA factor either through an application or an advice letter and tariffs, pursuant to the relevant provisions of title 40, articles 1 through 7 of the Colorado Public Utilities Law and of the Commission rules. The G-DSMCA shall be filed pursuant to the schedule provided in rule 4752.
- (h) The G-DSMCA filing shall include information and attachments as required in rule 4758. If the M & V evaluation required by rule 4755 yields benefit/costs test results that impact the allowable recovery of costs or currently approved bonus, then the utility shall include such adjustments in the G-DSMCA filing and tariffs.
- (i) If the projected DSM program costs have changed from those used to calculate the currently effective G-DSMCA cost or if a utility's deferred G-DSMCA cost balance increases or decreases sufficiently, the utility may file an application to revise its currently effective G-DSMCA factor to reflect such changes, provided that the resulting change to the G-DSMCA factor equates to a base rate change of at least one cent (\$0.01) per Mcf or Dth. A utility has the burden of proof to justify any interim G-DSMCA filings and the Commission has the discretion to consolidate the interim G-DSMCA filing with the next regularly scheduled annual G-DSMCA filing.
- (j) Applicability of the G-DSMCA factor. The G-DSMCA factor shall be separately calculated and applied to the utility sales gas base rate schedules of residential and non-residential customers.
- (k) Return on DSM program expenditures to be amortized. For utilities that choose to amortize the DSM program expenditure, the balance of a utility's investments in cost-effective DSM programs shall earn a return equal to the utility's current after-tax weighted average cost of capital.

- (l) Interest on under- or over-recovery. The amount of net interest accrued on the average monthly balance in sub-accounts of Account No. 186 (whether positive or negative), is determined by multiplying the monthly balance by an interest rate equal to the Commission-authorized after-tax weighted average cost of capital.
- (m) Calculation of the G-DSMCA factor. The G-DSMCA factor shall be calculated separately for residential and non-residential customers to at least the accuracy of two significant places.

**4758. Contents of Gas DSM Cost Adjustment Filing.**

- (a) General Provisions.
  - (I) A filing for a gas DSM cost adjustment (G-DSMCA) shall contain justifying information sufficient in detail to permit the Commission to determine the accuracy of the supporting calculation.
  - (II) The G-DSMCA filing shall include a complete set of work papers and all other documents relied on in preparing the adjustment.
  - (III) The provisions of this rule do not supersede other Commission rules that contain additional applicable filing requirements.
- (b) Specific Provisions. The filing shall contain detailed schedules and supporting documents that establish, at a minimum, the following:
  - (I) the detailed calculation of the G-DSMCA for each customer class based on the following general formula:
    - (A)  $\text{current G-DSMCA factor} = (\text{current G-DSMCA cost} + \text{deferred G-DSMCA cost}) / (\text{forecasted sales customer} \times \text{monthly service charge} + \text{forecasted sales gas quantity} \times \text{base rate});$  and
    - (B) the G-DSMCA factor will also include the current G-DSM bonus plus any adjustment necessary to previously approved G-DSM bonuses;
  - (II) a detailed schedule showing the computation of interest, as applicable, to deferred amounts;
  - (III) the absolute and percentage impact of the proposed rate on the base rates and on the total monthly bills of typical customers in each customer class;
  - (IV) a schedule detailing the allocation of costs to each customer class;
  - (V) proposed customer notice detailing rate impact and effective date;
  - (VI) proposed tariff implementing the proposed G-DSMCA; and

- (VII) if any gas DSM costs are proposed to be recovered by rate base treatment, with a return on the unamortized balance, a statement of current net operating earnings, a detailed calculation of the related revenue requirement and an attachment detailing any differences in the proposed rate base treatment compared to the regulatory practices employed by the Commission in its last general rate case for the applicant.

**4759. Bill Itemization.**

Consistent with rule 4406, a utility shall provide itemized gas cost information with gas DSM costs to all customers commencing with the first complete billing cycle in which the new rates are in effect.

**4760. Gas DSM Bonus (G-DSM Bonus) Applications.**

The Commission shall review each G-DSM bonus application submitted and shall determine the level of bonus, if any, for which the utility is eligible. The collection on any G-DSM bonus awarded will be apportioned between residential and nonresidential customers based on the proportion of residential and nonresidential net economic benefits used to calculate the G-DSM bonus.

- (a) G-DSM bonus filing requirements. The utility shall file its G-DSM bonus application as part of the annual report submitted to the Commission on the timetable set forth in rule 4752. The utility may request a G-DSM bonus not to exceed the lower of 25 percent of the expenditures or 20 percent of the net economic benefits of the DSM programs, applying the bonus calculation procedure set forth in rule 4754. The G-DSM bonus, as modified and approved by the Commission, shall not count against a gas utility's authorized rate of return or be considered as net operating earnings in rate proceedings.
- (b) Contents of G-DSM bonus filing. In the G-DSM bonus filing, the utility shall submit to the Commission the following, at a minimum:
  - (I) documented expenditures on DSM programs for the current G-DSMCA period;
  - (II) gas savings for the calendar year for which the bonus is to be awarded estimated following and the techniques approved in the DSM plan. The utility shall explain whether the actual gas savings are validated through the measurement and verification process as approved in the utility's DSM plan;
  - (III) estimated cost-effectiveness of program expenditures for the current G-DSMCA period in terms of the amount of gas saved per unit of program expenditures;
  - (IV) actual gas savings and the techniques used to calculate these gas savings for the prior G-DSMCA period. The utility shall explain whether the actual gas savings are validated through the measurement and verification process, pursuant to rule 4755;
  - (V) actual cost-effectiveness of program expenditures for the prior G-DSMCA period in terms of the amount of gas saved per unit of program expenditures. The utility shall explain whether the actual cost effectiveness of program expenditures is validated through the measurement and verification process, pursuant to rule 4755; and
  - (VI) proposed tariffs containing rates to collect the bonus over 12 months.

- (c) The Commission shall issue a decision approving, modifying, or disapproving a DSM bonus application within 90 days of the utility filing of the application. The Commission shall allow oral testimony and shortened discovery response times as necessary to expedite the schedule.
- (d) Accounting for G-DSM bonus. Accounting for G-DSM bonus shall follow what has been prescribed for G-DSMCA costs, specifically in regard to interest on over- and under- recovery. A separate sub-account in Account No. 186 shall be created for any deferred G-DSM bonus amount.
- (e) Prudence review and adjustment of G-DSM bonus. If the Commission finds that the actual performance varies from performance values used to calculate the G-DSM bonus in rule 4754, then an adjustment shall be made to the amount of G-DSM bonus award. Any true-up in G-DSM bonus will be implemented on a prospective basis.

**4761. – 4799. [Reserved]**

**MASTER METER OPERATORS**

**4800. Scope and Applicability.**

These rules are applicable to any person who purchases gas service from a serving utility for the purpose of delivery of that service to end-users whose aggregate usage is measured by a master meter or other composite measurement device.

**4801. Definitions.**

The following definitions apply to rules 4800 through 4805, unless a specific statute or rule provides otherwise. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- (a) "Check-meter" means a meter or other composite measurement device used by a master meter operator to determine gas consumption by end-users served by the master meter operator.
- (b) "Master meter" means a meter or other composite measurement device which a serving utility uses to bill a master meter operator.
- (c) "Master meter operator" (MMO) means a person who purchases gas service from a serving utility for the purpose of delivering that service to end-users whose aggregate usage is measured by a master meter.
- (d) "Refund" means a refund, rebate, rate reduction, or similar adjustment.
- (e) "Serving utility" means the utility from which the master meter operator receives the gas service which the master meter operator then delivers to end-users.

**4802. Exemption from Rate Regulation.**

- (a) Pursuant to § 40-1-103.5, C.R.S., and by this rule, the Commission exempts from rate regulation under Articles 1 to 7 of Title 40, C.R.S., a master meter operator which is in compliance with rules 4803 and 4804.
- (b) A master meter operator which is not in compliance with rules 4803 and 4804 is subject to rate regulation under Articles 1 to 7 of Title 40, C.R.S., and shall comply with the applicable rules.

**4803. Exemption Requirements.**

- (a) In order to retain its exemption from rate regulation, a MMO shall do the following.
  - (I) As part of its billing for utility service, the MMO shall charge its end-users only the actual cost billed to the MMO by the serving utility. The MMO shall not charge end-users for any other costs (such as, without limitation, the costs of construction, maintenance, financing, administration, metering, or billing for the equipment and facilities owned by the MMO) in addition to the actual costs billed to the MMO by the serving utility.
  - (II) If the MMO bills its end-users separately for service, the sum of such billings shall not exceed the amount billed to the MMO by the serving utility.
  - (III) If the MMO bills its end-users separately for service, the MMO shall pass on to its end-users all refunds the MMO receives from the serving utility or otherwise.
  - (IV) The MMO shall establish procedures for giving notice of a refund to those who are not current end-users but who were end-users during the period for which the refund is paid.
  - (V) A master meter operator shall retain, for a period of not less than three years, all records of original utility billings made to the master meter operator and all records of billings and refunds made by the master meter operator to its end-users, including certification of mailing, when applicable.
- (b) In order to retain its exemption from rate regulation, a MMO shall not resell the services provided by a serving utility to the MMO for profit. Resale of services provided by a serving utility to a MMO for profit is a basis for revocation of an exemption from rate regulation.
- (c) A MMO may check-meter tenants, lessees, or other persons to whom the gas ultimately is distributed but may do so only if the following conditions are met:
  - (I) the check-meter is used solely for the purpose of determining a basis for the MMO to allocate the costs of the serving utility; and
  - (II) the MMO does not receive more than the actual amount billed to the MMO by the serving utility from the MMO's customers.

**4804. Refunds.**

- (a) When a serving utility notifies a MMO of a refund or when a refund is otherwise made related to the services provided by the serving utility to the MMO, a MMO shall refund an allocated share of the refunds to its customers within 90 days after receipt of the notice or refund from the serving utility. The notification shall be made either by first-class mail with a certificate of mailing or by inclusion in any monthly or more frequent regular written communication. The MMO shall retain the certification of mailing pursuant to subparagraph 4803(a)(V). The MMO shall also notify former customers who were end-users during the period for which the refund is made that refunds are available, to the extent such former customers can be located.
- (b) A MMO may retain any portion of a refund which is related to service taken by the MMO at its own facilities after refunds are made to its current and former customers.
- (c) If the aggregate amount of a refund which remains unclaimed after 90 days exceeds \$100, the MMO shall contribute that unclaimed amount to the energy assistance organization in accordance with rules 4410(d), (f), and (g). If the aggregate amount which remains unclaimed after 90 days does not exceed \$100, the MMO may retain the aggregate amount.

**4805. Complaints, Penalties, and Revocation of Exemption.**

- (a) Pursuant to rules 1301 and 1302, a person (including without limitation anyone taking service from a master meter operator) may make an informal complaint to the Commission or may file a formal complaint with the Commission with the respect to an alleged violation of rules 4803 and 4804.
- (b) As a result of a complaint or on its own motion, the Commission will investigate complaints concerning MMOs. If the Commission determines after investigation that an MMO has violated any of the requirements of rules 4803 and 4804, the MMO may have its exempt status revoked or may be subject to penalties as set forth in § 40-7-107, C.R.S., or both.

**4806. – ~~4899975~~. [Reserved].**

**~~GAS PIPELINE SAFETY~~**

**~~General Provisions~~**

**~~4900.—Scope and Applicability.~~**

- ~~(a) The gas pipeline safety rules prescribe requirements for construction, operation, and maintenance of pipeline facilities, and for reporting by operators. Pursuant to these rules, the Commission conducts its pipeline safety program activities under 49 U.S.C. § 60105 and § 40-2-101, C.R.S. The statutory authority permitting the Commission to enter into cooperative agreements with federal agencies, to adopt and to create rules to administer and to enforce 49 U.S.C. §§ 60101, et seq., can be found at §§ 40-2-115 and 40-7-117, C.R.S.~~
- ~~(b) Rules 4900 through 4975 apply to, establish, and govern the:~~

- ~~(I) — Reporting by operators of gas pipeline systems of incidents, gas related events, safety-related conditions, damage statistics, notice of major projects, and annual pipeline summary data. [rules 4910 through 4929].~~
- ~~(II) — Enforcement by Staff of the Rules Regulating Gas Pipeline Safety [rules 4930 through 4949].~~
- ~~(III) — Adoption of minimum safety standards for transportation of natural gas and other gas by pipeline, specific requirements for rural gathering, procedural updates, and amendment of plans or procedures, [rules 4950 through 4959].~~
- ~~(IV) — Adoption of minimum safety standards for liquefied natural gas facilities [rules 4960 through 4969].~~
- ~~(V) — Adoption and enforcement of a drug and alcohol testing program [rule 4970].~~
- ~~(c) — Nothing in these rules shall be construed to exempt interstate or gathering pipeline operators from complying with § 9-1.5-105, C.R.S.~~

**4901. — Definitions.**

The following definitions apply to rules 4900 through 4975, except where a specific statute or rule provides otherwise or where the context otherwise indicates. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- ~~(a) — "Chief" means the program manager of the Gas Pipeline Safety Section of the Commission.~~
- ~~(b) — "Damage," when used in reference to a pipeline, means the penetration or destruction of any protective coating of an underground pipeline, the partial or complete severance of an underground pipeline, or the denting or puncturing of an underground pipeline.~~
- ~~(c) — "Damage prevention program" means an operator's written program to prevent damage to a pipeline by excavation, as defined in 49 C.F.R. § 192.614.~~
- ~~(d) — "Direct sales meter" means a meter that measures the transfer of gas to a direct sales customer purchasing gas for its own consumption.~~
- ~~(e) — "Direct sales pipeline" means a pipeline not under the jurisdiction of the Federal Energy Regulatory Commission and which runs from an intrastate or interstate transmission pipeline, a production facility, or a gathering pipeline to a direct sales meter, pressure regulator, or emergency valve, whichever is the furthest downstream.~~
- ~~(f) — "Distribution pipeline" means a pipeline other than a transmission pipeline or a gathering pipeline.~~
- ~~(g) — "Excavation" means the moving or removing of earth by means of any tools, equipment, or explosives and includes (without limitation) auguring, boring, backfilling, ditching, drilling, grading, plowing-in, pulling-in, ripping, scraping, trenching, or tunneling.~~
- ~~(h) — "Gas" means natural gas, flammable gas, toxic or corrosive gas, and petroleum gas.~~



- ~~(i) "Gathering pipeline" means a pipeline that transports gas from a current production facility to a transmission pipeline or main.~~
- ~~(j) "Hazardous facility" means a pipeline facility that, if allowed to go into operation or to remain in operation, would be hazardous to life and property.~~
- ~~(k) "Incident" means a release of gas from a pipeline covered by 49 C.F.R. § 192.1, or a release of liquefied natural gas or gas from a LNG facility, which results in any of the following:
  - ~~(I) Death or personal injury necessitating in-patient hospitalization.~~
  - ~~(II) Estimated property damage of \$50,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost.~~
  - ~~(III) An event that results in an emergency shutdown of a LNG facility.~~
  - ~~(IV) An unintentional event resulting in an estimated gas loss of three million cubic feet or more.~~
  - ~~(V) An event that is significant, in the judgment of the operator, even though it does not meet the criteria of subparagraphs (I), (II), (III), or (IV) of this paragraph.~~~~
- ~~(l) "Liquefied Natural Gas" or "LNG" means natural gas or synthetic gas which has methane (CH<sub>4</sub>) as its major constituent and which has been changed to a liquid.~~
- ~~(m) "LNG facility" means a pipeline facility that is used for liquefying natural gas or synthetic gas or for transferring, storing, or vaporizing liquefied natural gas.~~
- ~~(n) "Main" means a distribution line that serves, or is designed to serve, as a common source of supply for more than one service line.~~
- ~~(o) "Major project" means the construction of any new pipeline facility covered by 49 C.F.R. § 192.1, the repair, or upgrade of a pipeline segment, that originally is estimated to cost five hundred thousand dollars or more. As used in this rule, cost includes only the direct costs associated with the construction, repair, or upgrade.~~
- ~~(p) "Master meter system" means a pipeline system for distributing gas within a definable area (for example, a mobile home park) where the operator or owner purchases gas from an outside source for delivery through a pipeline system to an end user.~~
- ~~(q) "Municipality" means a city, town, or village in the State of Colorado.~~
- ~~(r) "Natural Gas Pipeline Act" means the federal statute found at 49 U.S.C. §§ 60101, et seq., as amended.~~
- ~~(s) "Operator" means a person who is engaged in the transportation of gas, or who has the right to bury underground pipeline, or who is both engaged in the transportation of gas and has the right to bury underground pipeline. "Operator" also may include an owner, such as a pipeline corporation.~~

- ~~(t) "OPS" means the Office of Pipeline Safety, a unit of the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the United States Department of Transportation.~~
- ~~(u) "Person" means an individual, firm, joint venture, partnership, corporation, association, municipality, cooperative association, or joint stock association, and includes any trustee, receiver, assignee, or personal representative thereof.~~
- ~~(v) "Pipeline" or "pipeline system" means all parts of those physical intrastate facilities through which gas moves in transportation, including, but not limited to, pipes, valves, and other appurtenances attached to pipes, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.~~
- ~~(w) "Pipeline facility" means new and existing intrastate pipelines, rights-of-way, and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.~~
- ~~(x) "Production facility" means flowline and associated equipment used at a wellsite in producing, extracting, recovering, lifting, stabilizing, initial separating and/or treating, initial dehydrating, disposal, and above-ground storing of liquid hydrocarbons, associated liquids, and associated natural hydrocarbon gases. A production facility may include flowlines up to a central delivery point directly associated with a specific producing field. To be a production facility under this definition, a flowline must be used in the process of extracting hydrocarbons and associated liquids from the ground or from facilities where hydrocarbons are produced or must be used for disposal or injection in reservoir maintenance or recovery operations.~~
- ~~(y) "Propane gas system" means a pipeline system serving ten or more structures from a single tank.~~
- ~~(z) "Roadway" means a main public artery, highway, or interstate highway.~~
- ~~(aa) "Service line" means a distribution line that transports gas, or is designed to transport gas, from a common source of supply to an individual customer, to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a single meter header or manifold. A service line ends at the outlet of the customer meter or at the connection to a customer's piping, whichever is furthest downstream, or at the connection to customer piping if there is no meter.~~
- ~~(bb) "Service regulator" means the device on a service line that controls the pressure of gas delivered from a higher pressure to the pressure provided to the customer. A service regulator may serve one customer or multiple customers through a meter header or manifold.~~
- ~~(cc) "Specified Minimum Yield Strength" or "SMYS" means:~~
- ~~(I) For steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification.~~
- ~~(II) For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with 49 C.F.R. § 192.107(b).~~
- ~~(dd) "Staff" means the Staff of the Gas Pipeline Safety Section of the Commission.~~

~~(ee) "Transmission pipeline" means a pipeline, other than a gathering pipeline or distribution pipeline, that does one of the following:~~

~~(I) Transports gas from a gathering pipeline or storage facility to a distribution center, or storage facility.~~

~~(II) Operates at a hoop stress of 20 percent or more of SMYS.~~

~~(III) Transports gas within a storage field.~~

~~(IV) Is a direct sales pipeline serving a large volume customer not downstream of a distribution center, which may include, but not be limited to, factories and power plants.~~

~~(ff) "Transportation of gas" means the gathering, transmission, distribution, or storage of gas within the State of Colorado that is not subject to the jurisdiction of the Federal Energy Regulatory Commission under the Natural Gas Act.~~

**~~4902. Incorporation by Reference.~~**

~~(a) The Commission adopts by reference the minimum federal safety standards for the transportation of natural gas and other gas by pipeline of the OPS that are published in 49 C.F.R. Part 192 (October 1, 2012). This incorporation by reference does not include later amendments to, or editions of, 49 C.F.R. Part 192.~~

~~(b) The Commission adopts by reference the federal safety standards for liquefied natural gas facilities of the OPS that are published in 49 C.F.R. Part 193 (October 1, 2012). This incorporation by reference does not include later amendments to, or editions of, 49 C.F.R. Part 193.~~

~~(c) The Commission hereby adopts by reference the drug and alcohol testing program of the OPS published in 49 C.F.R. Parts 40 and 199 (October 1, 2012). This incorporation by reference does not include later amendments to, or editions of, 49 C.F.R. Parts 40 and 199.~~

~~(d) Any material incorporated by reference in this rule may be examined at the offices of the Commission, 1560 Broadway, Suite 250, Denver, Colorado 80202, during normal business hours, Monday through Friday, except when such days are state holidays. Certified copies of the incorporated standards shall be provided at cost upon request. The Director or the Director's designee will provide information regarding how the incorporated standards may be examined at any state public depository library.~~

**~~4903. Conflict.~~**

~~In the event of a conflict between the provisions of 49 C.F.R. Parts 40, 192, 193, or 199 and the rules 4900 through 4975 regarding the administrative, the enforcement, and the reporting requirements, the rules 4900 through 4975 shall apply.~~

**4904. Interpretation.**

- (a) ~~An operator may request a regulatory interpretation of any of these rules by submitting a written request to the Chief. The requestor shall include his or her return address and the specific application and rule reference with the request.~~
- (b) ~~After a request for interpretation is received, the Chief will notify the requestor of the disposition of the request and if additional information is required.~~
- (c) ~~If the request is consistent with the state pipeline safety program and is justified, the Chief will provide the Federal Administrator for Pipeline Safety a written recommendation with terms and conditions as are appropriate.~~
- (d) ~~The interpretation is effective upon approval by the Federal Administrator for Pipeline Safety or, no action is taken by the Federal Administrator for Pipeline Safety, 60 days after the receipt of the recommendations from the Chief.~~

**4905. Special Permit.**

- (a) ~~The Commission may grant a request for a special permit authorizing a variance from any of these rules in accordance with § 40-2-115, C.R.S., 49 U.S.C. § 60118(d), and the Commission's Rules of Practice and Procedure.~~
- (b) ~~Under § 40-2-115, C.R.S. and 49 U.S.C. § 60118(d) the Commission has the authority to grant special permits in emergency situations. An emergency special permit will be granted if it is in the public interest, is not inconsistent with pipeline safety, and is necessary to address an actual or impending emergency involving pipeline transportation, including an emergency caused by a natural or manmade disaster. An emergency pipeline special permit is an order by which the Commission may temporarily modify compliance with state pipeline regulations for affected pipeline owners or operators and the Commission may waive compliance with a safety regulation if, after receiving notice, the OPS concurs in the action.~~
  - (l) ~~The Commission will determine on a case-by-case basis what duration is necessary to address the emergency. However, as required by statute, no emergency special permit may be issued for a period of more than 60 days. Each emergency special permit will automatically expire on the date stated on the permit.~~
  - (ll) ~~Each request should include the following information:~~
    - (A) ~~Name of requestor and indication of whether requestor is an owner or operator;~~
    - (B) ~~Duration of the emergency special permit;~~
    - (C) ~~Specific regulations from which the owner or operator seeks relief;~~
    - (D) ~~An explanation of the actual or impending emergency;~~
    - (E) ~~Specific reasons the special permit is necessary (e.g., lack of accessibility, damaged equipment, gas supply or temporary by-pass);~~

- ~~(F) — A description of the pipeline for which special permit is sought, including:
    - ~~(i) — the mileage or footage of pipeline to be covered and the counties in which it is located;~~
    - ~~(ii) — the year the pipeline was installed;~~
    - ~~(iii) — all pipeline facilities such as pump and compressor stations that this permit will affect, and;~~
    - ~~(iv) — the material, thickness, diameter and operating pressure of the pipeline.~~~~
  - ~~(G) — A statement indicating whether and how operating the pipeline pursuant to an emergency special permit is in the public interest (e.g., continuity of service, service restoration);~~
  - ~~(H) — Proposed alternatives to compliance with the regulation (e.g., additional inspections and tests, shortened reassessment intervals);~~
  - ~~(I) — Measures to be taken after the emergency situation or permit expires whichever comes first to confirm long-term operational reliability of the facility, and;~~
  - ~~(J) — A certification that operation of the owner or operator's pipeline under the requested emergency special permit would not be inconsistent with pipeline safety.~~
- ~~(c) — An operator may propose to deviate from the standards adopted by reference to part 192 and alter the frequency of periodic inspections and tests on the basis of an engineering analysis and risk assessment.~~
- ~~(I) — An alternative frequency of inspections and tests required under part 192 will be granted if it is not inconsistent with pipeline safety. For intrastate facilities, an operator must submit its proposal to the Chief at least 120 days before the requested effective date. After receiving notice, the Chief will confer with the OPS on the action requested by the operator. The Chief may accept the proposal, with or without conditions and limitations, on a showing that the operator's proposal, which includes the adjusted interval, will provide an equal or greater overall level of safety.~~
  - ~~(II) — An operator may implement an approved reduction in the frequency of a periodic inspection or test only where the operator has developed and implemented an integrity management program that provides an equal or improved overall level of safety despite the reduced frequency of periodic inspections.~~
  - ~~(III) — Each request must include the following information:
    - ~~(A) — Name of the owner or operator;~~
    - ~~(B) — Duration of the deviation proposal;~~~~

- ~~(C) — Specific regulations from which the owner or operator seeks relief;~~
- ~~(D) — A description of the pipeline for which the deviation is sought, including:
  - ~~(i) — the mileage or footage of pipeline to be covered and the counties in which it is located;~~
  - ~~(ii) — the year the pipeline was installed;~~
  - ~~(iii) — all pipeline facilities that this request will affect, and;~~
  - ~~(iv) — the material, thickness, diameter and operating pressure of the pipeline.~~~~
- ~~(E) — Proposed alternatives to compliance with the regulation (e.g., additional inspections and tests, shortened reassessment intervals); and~~
- ~~(F) — A certification that operation of the owner or operator's pipeline under the requested alternative frequency of periodic inspections and tests would not be inconsistent with pipeline safety.~~

~~(d) — Grants and denials. If the Chief determines that the permit to deviate complies with the requirements of this rule and that the deviation from the regulation or standard is not inconsistent with pipeline safety, the Chief may grant the request, in whole or in part, on a temporary or permanent basis. Conditions may be imposed on the request if the Chief concludes that they are necessary to assure safety, or are otherwise in the public interest. If the Chief determines that the application does not comply with the requirements of this rule or that a deviation is not justified, the request for deviation will be denied. Whenever the Chief grants or denies a request for deviation, the notice of the decision will be provided to the applicant. All special permits will be posted on the PUC website at <http://cdn.colorado.gov/cs/Satellite/DORA-PUC/CBON/DORA/1251632608618>~~

#### **4906. — Alert Bulletins.**

~~An alert or advisory bulletin may be disseminated to an operator based on recommendations from the National Transportation Safety Board, the OPS, or as a result of a situation which may pose a threat to pipeline systems or the public. After receiving information concerning an alert or advisory bulletin, an operator shall take appropriate action to review and to revise its design, installation, and/or its operating and maintenance procedures.~~

#### **4907. — 4909. — [Reserved].**

#### **Filing Incident, Safety-Related Condition, Major Project, Damage and Locate Summary, and Annual Reports**

#### **4910. — Submission of Reports.**

~~(a) — An operator must submit reports required by these rules, except notices of major projects, and of pipeline damage and locate summary information, electronically to the OPS at <http://opsweb.phmsa.dot.gov>.~~

~~(b) — A copy of each report submitted to the OPS shall be furnished via U.S. mail, emailed to the gas pipeline safety contact found on the Commission's Pipeline Safety Website in a .pdf searchable document, or by a facsimile to (303) 894-2065. In lieu of sending a copy of an OPS report, operators may supply operator identification number and PIN number information to permit Staff access to the OPS reporting site.~~

**4911. — Telephonic Reports.**

~~(a) — As soon as possible after discovery, but generally not to exceed two hours after discovery, an operator must telephonically report any incident to the Staff at (303) 894-2854 and to the National Response Center of the U.S. Department of Transportation at (800) 424-8802 or electronically at <http://www.nrc.uscg.mil>.~~

~~(b) — The operator of a pipeline, including a gathering pipeline in a class 1, 2, 3, or 4 area, of a LNG system, of a master meter system, or of a propane system, must telephonically report to the Staff at (303) 894-2854, within two hours after discovery, any of the following events:~~

~~(I) — A gas leak that occurs on the pipeline, the LNG system, the master meter system, or the propane system and that results in the evacuation of 50 or more people from a normally occupied building or property.~~

~~(II) — A gas leak that occurs on the pipeline, the LNG system, the master meter system, or the propane system and that results in the closure of a roadway or railroad.~~

~~(c) — A telephonic report made pursuant to paragraphs (a) or (b) of this rule must include the following information:~~

~~(I) — The name and telephone number of the operator and the contact.~~

~~(II) — The location of the incident or event.~~

~~(III) — The date and time of the incident or event.~~

~~(IV) — The number of fatalities and personal injuries, if any.~~

~~(V) — All other significant facts that are known by the person making the report that are relevant to the cause of the incident or event and the extent of the damage.~~

~~(VI) — The National Response Center control number, if known.~~

**4912. — Written Reports by Operators of Distribution Systems.**

~~(a) — Except as provided in paragraph (c) of this rule, an operator of a distribution pipeline system must submit OPS Form PHMSA F 7100.1 Incident Report: Gas Distribution System in the manner required by rule 4910 as soon as possible after the detection of an incident, but not later than 30 days after detection.~~

~~(b) — After submitting an incident report pursuant to paragraph (a) of this rule, an operator must submit a supplemental report in the manner required by rule 4910 if the operator obtains additional,~~

~~relevant information. The operator must submit the supplemental report as soon as possible, but not more than 60 days after obtaining the additional information.~~

- ~~(c) — An operator of a master meter system or a propane gas system is not required to file an incident report.~~
- ~~(d) — Except as provided in paragraph (e) of this rule, an operator of a distribution pipeline system must submit an annual report for its intrastate pipeline system on OPS Form PHMSA F 7100.1-4 Distribution system: Annual Report in the manner required by rule 4910. This report shall be submitted annually by March 15 for the preceding calendar year.~~
- ~~(e) — An operator of a propane gas system which serves fewer than 100 customers from a single source, a master meter system, or a LNG facility is not required to submit an annual report.~~

#### ~~4913. — Written Reports by Operators of Transmission and Gathering Systems.~~

- ~~(a) — An operator of a transmission pipeline system or an OPS regulated type A or type B gathering pipeline segment as defined in 49 C.F.R. Part 192 must submit OPS Form PHMSA F 7100.2 Transmission and Gathering system: Incident Report in the manner required by rule 4910 as soon as possible after the detection of an incident, but not later than 30 days after detection.~~
- ~~(b) — After submitting an incident report pursuant to paragraph (a) of this rule, an operator must submit a supplemental report in the manner required by rule 4910 if the operator obtains additional, relevant information. The operator shall submit the supplemental report as soon as possible, but not more than 60 days after obtaining the additional information. The supplemental report shall reference the original report by date and subject.~~
- ~~(c) — An operator of a transmission pipeline system or an OPS regulated type A or type B gathering pipeline segment(s) as defined in 49 C.F.R. Part 192 must submit OPS Form PHMSA F 7100.2.1 Transmission and Gathering system: Annual Report information in the manner required by rule 4910. This report shall be submitted annually by March 15 for the preceding calendar year.~~

#### ~~4914. — Reports of Safety-Related Conditions.~~

- ~~(a) — Except as provided in paragraph (d) of this rule, an operator must submit a safety-related condition report in the manner required by rule 4910 on the existence of any of the following safety-related conditions with respect to a regulated pipeline in service:
  - ~~(I) — In the case of a pipeline that operates at a hoop stress of 20 percent or more of its SMYS, (a) general corrosion that has reduced the wall thickness to less than that required for the maximum allowable operating pressure and (b) localized corrosion pitting to a degree where leakage might result.~~
  - ~~(II) — Unintended movement or abnormal loading by naturally occurring environmental causes (for example, earthquakes, landslides, or floods) that impairs the serviceability or integrity of a pipeline.~~~~



- ~~(III) — Any crack or other material defect that impairs the structural integrity or reliability of a LNG facility that contains, controls, or processes gas or LNG.~~
- ~~(IV) — Any material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop stress of 20 percent or more of its SMYS.~~
- ~~(V) — Any malfunction or operating error that causes the pressure of a pipeline or LNG facility that contains or processes gas or LNG to rise above its maximum allowable operating pressure (or working pressure for LNG facilities) plus the build-up allowed for operation of pressure limiting or control devices.~~
- ~~(VI) — A leak in a pipeline or LNG facility that contains or processes gas or LNG that constitutes an emergency.~~
- ~~(VII) — Inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of a LNG storage tank.~~
- ~~(VIII) — Any safety related condition that could lead to an imminent hazard and that causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent or more reduction in operating pressure or shutdown of operation of a pipeline or a LNG facility that contains or processes gas or LNG.~~
- ~~(b) — A report of a safety-related condition must be submitted in the manner required by rule 4910, within five business days (not including Saturday, Sunday, or federal or State holidays) after the day on which the operator or its representative first determines that a safety-related condition exists. The report shall not be submitted later than ten business days after the day an operator or its representative discovers the condition. Separate conditions may be reported in a single report if they are closely related.~~
- ~~(c) — The report shall be headed "Safety-Related Condition Report" and must provide the following information:
  - ~~(I) — Name and principal address of operator.~~
  - ~~(II) — Date of report.~~
  - ~~(III) — Name, job title, and business telephone number of the person submitting the report.~~
  - ~~(IV) — Name, job title, and business telephone number of the person who determined that the condition exists.~~
  - ~~(V) — Date the condition was discovered and, if different, date condition was first determined to exist.~~
  - ~~(VI) — Location of the condition. This requires identification of the town, city, or county in which the condition exists and, as appropriate, the nearest street address, milepost, or landmark; and the name of pipeline.~~~~

- ~~(VII) — Description of the condition, of the circumstances leading to its discovery, of any significant effects the condition has on safety, and of the type of gas transported or stored.~~
  - ~~(VIII) — Description of the corrective action taken (including reduction of pressure or shutdown) before the report was submitted.~~
  - ~~(IX) — Description of any planned future follow-up or corrective action, including the anticipated schedule for starting and concluding such action.~~
- ~~(d) — A written report need not be made for any safety-related condition that:~~
- ~~(I) — Exists on a regulated gathering system as defined by 49 C.F.R. Part 192 and where a MAOP produces a hoop stress less than 20 percent of SMYS, a master meter system, a propane gas system, or a customer-owned service line.~~
  - ~~(II) — Is an event or results in an event which occurs before a permanent repair or replacement pertaining to an already reported incident can be completed.~~
  - ~~(III) — Exists on a pipeline (other than a LNG pipeline) that is more than 220 yards from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad or roadway.~~
  - ~~(IV) — Is corrected by permanent repair or replacement in accordance with applicable safety standards within five business days of the day on which the operator first determines that the condition exists, but not later than ten business days after an operator or its representative discovers the condition. This subparagraph does not apply to localized corrosion pitting on an effectively coated and cathodically protected pipeline.~~

**~~4915. — Reporting of Pipeline Damage and of Locate Information.~~**

- ~~(a) — An operator of a local distribution company or municipal operated system must file with the Commission information concerning general pipeline damage and pipeline locate information annually, by March 15. This report applies to damage to underground pipelines, excluding any damage to electrically conductive tracer wire.~~
- ~~(b) — Each report shall include the following pipeline information:~~
  - ~~(I) — Total number of facility locates transmitted from the Utility Notification Center of Colorado (UNGC);~~
  - ~~(II) — Total number of excavation related damages to mains;~~
  - ~~(III) — Total number of excavation related damages to services;~~
  - ~~(IV) — Total number of excavation related damages to transmission pipelines;~~
  - ~~(V) — Total number of excavation damage due to excavation practice being insufficient;~~

~~(VI) — Total number of excavation damage due to operator locator practice being insufficient;~~

~~(VII) — Total number of excavation damage due to contract locator practice being insufficient;~~

~~(VIII) — Total number of excavation damage due to no facility locate requested; and~~

~~(IX) — Total number of excavation damage due to other reasons. A root cause explanation must be included with each reported damage under this category.~~

~~(c) — Pipeline operators are required to be Tier 1 members and report underground facility damages to the Utility Notification Center of Colorado (UNCC-Colorado 811) “Colorado Damage Reporting Tool DIRT” at <https://www.damagereporting.org/uncc>.~~

~~(d) — Additional specific damage information may be requested under paragraph 4932(c).~~

**4916. — Filing Notices of Major Project.**

~~(a) — Written notice of a major project must be submitted to the Staff not later than 20 business days prior to the scheduled commencement date of the project, if practicable.~~

~~(b) — The notice shall contain the following information:~~

~~(I) — The type of construction or repair.~~

~~(II) — The date of commencement.~~

~~(III) — The estimated period of construction or repair.~~

~~(IV) — Pipeline design specifications, and the test medium (for example, gas, inert gas, water).~~

~~(V) — The location of the construction or repair.~~

~~(VI) — The estimated cost of the construction or repair project.~~

**4917. — 4929. — [Reserved].**

**Procedure For Enforcement**

**4930. — Service.**

~~(a) — An order, notice, complaint or other document required to be served under these rules shall be served personally or by registered or certified mail.~~

~~(b) — Service upon an operator’s authorized representative or agent constitutes service upon that operator.~~

~~(c) — Service by registered or certified mail is complete upon mailing. An official U.S. Postal Service receipt evidencing a registered or certified mailing constitutes prima facie evidence of service.~~

**4931. Subpoenas.**

- (a) ~~The Commission, an Administrative Law Judge, or the Director may issue a subpoena in accordance with rule 1406.~~
- (b) ~~Rule 45 of the Colorado Rules of Civil Procedure, except as provided in rule 1406 and §§ 40-6-102 and 103, C.R.S., shall govern a subpoena issued under this rule.~~
- (c) ~~A subpoena issued under this rule may be enforced in the district court, as provided by § 40-6-103(2), C.R.S.~~

**4932. Inspections and Testing.**

- (a) ~~As authorized by the Chief, Staff may enter upon, to inspect, and to examine, at reasonable times, an operator's right of way or easement, new and existing piping, valves, and other above ground appurtenances attached to pipes, or, upon request of the OPS, an interstate pipeline to determine compliance with 49 U.S.C. §§ 60101 et seq., with these rules, with Commission orders, or with orders issued pursuant to these rules. If requested, Staff shall present Commission credentials at the time of the inspection.~~
- (b) ~~Staff may require testing of an operator's pipeline. Staff shall make every effort to negotiate with the operator of the pipeline a mutually acceptable testing plan before performing such tests.~~
- (c) ~~If information is needed, the Chief may send the operator a request for specific information to be answered within 45 days after receipt of the request.~~
- (d) ~~When information obtained from an inspection, testing, a request for specific information, or other sources indicates that enforcement action is warranted, the Chief may do one of the following:~~
  - (I) ~~Serve on the operator a Warning Letter pursuant to rule 4933 or a Notice of Probable Violation pursuant to rule 4934.~~
  - (II) ~~File a formal complaint with the Commission requesting a Hazardous Facilities Order pursuant to rule 4940.~~

**4933. Warning Letters.**

- (a) ~~If the Chief believes that an operator has committed a probable violation of 49 U.S.C. §§ 60101 et seq., of these rules, of a Commission order, or of an order issued pursuant to these rules, the Chief may serve a warning letter on the operator advising the operator of the probable violation and advising the operator to correct the probable violation or be subject to an enforcement action under these rules.~~
- (b) ~~Within 30 days after receipt of a warning letter, an operator shall respond to the Chief by submitting a written explanation, information, or other material in answer to the allegations contained in the warning letter.~~

**4934. Notices of Probable Violation.**

- (a) ~~If the Chief believes that an operator has committed a probable violation of 49 U.S.C. §§ 60101, et seq., of these rules, of a Commission order, or of an order issued pursuant to these rules, the Chief may commence an enforcement proceeding against an operator by serving the operator with a notice of probable violation charging such person with a probable violation of 49 U.S.C. §§ 60101, et seq., of these rules, of a Commission order, or of an order issued pursuant to these rules.~~
- (b) ~~A notice of probable violation served pursuant to paragraph (a) of this rule shall include:~~
- ~~(I) A statement of the facts upon which the notice of probable violation is based.~~
  - ~~(II) A statement of the law, rule(s), or order(s) that the operator is alleged to have violated.~~
  - ~~(III) A statement of the response options available to the operator.~~
  - ~~(IV) Either or both of the following:
    - ~~(A) A proposed civil penalty, including the maximum amount of a penalty for which the operator may be liable, pursuant to rule 4936.~~
    - ~~(B) A proposed compliance directive pursuant to rule 4937.~~~~

**4935. Response Options to Amendment and to Notice of Probable Violation.**

- (a) ~~Within 30 days after receipt of an amendment issued pursuant to rule 4954 or of a notice of probable violation issued pursuant to rule 4934, an operator shall respond in writing to the Chief in one or more of the following ways:~~
- ~~(I) The operator may pay the proposed civil penalty in full.~~
  - ~~(II) The operator may agree to the proposed compliance directive.~~
  - ~~(III) The operator may submit an offer in compromise of the proposed civil penalty. The operator may make an offer in compromise by submitting a check or money order for the amount offered. The Chief will consider the offer in compromise in light of the criteria established in § 40-7-117(2), C.R.S., and of other relevant factors. If the offer in compromise is accepted by the Chief, the operator will be notified in writing that the acceptance is in full settlement of the proposed civil penalty. If an offer in compromise is rejected by the Chief, the check or money order will be returned to the operator with a written notification. Within ten days after receipt of a notice of rejection, the operator shall respond to the Chief in one or more of the ways provided in paragraph (a) of this rule.~~
  - ~~(IV) The operator may request the execution of a consent stipulation pursuant to rule 4939.~~
  - ~~(V) The operator may submit a written explanation, information, or other material in response to the allegations contained in the notice of probable violation; in objection to the proposed compliance directive; or in mitigation of the proposed civil penalty.~~

~~(VI) — The operator may request a hearing. If an operator requests a hearing, the Chief may amend the notice of probable violation at any time up to 30 days prior to the first day of hearing. After that time, a notice of probable violation may be amended only in accordance with the Commission's Rules Regulating Practice and Procedure.~~

~~(b) — If the operator fails to respond as provided in this rule, the notice of probable violation shall be set for hearing.~~

~~(c) — If the operator fails to respond as provided in this rule, the notice of amendment shall be set for hearing.~~

**4936. — Civil Penalties.**

~~(a) — As provided in §§ 40-2-115(2) and 40-7-117, C.R.S., an operator who violates 49 U.S.C. §§ 60101, et seq., these rules, an order of the Commission, or an order issued under these rules shall be subject to a civil penalty not to exceed \$100,000 per violation. Each day of a continuing violation shall constitute a separate violation. In the case of a group or series of related violations, the aggregate amount of such penalties shall not exceed \$1,000,000.~~

~~(b) — No operator shall be subject to a second or additional civil penalty for violations based on the same act.~~

**4937. — Compliance Directives.**

~~When the Chief serves a notice of probable violation on an operator, the Chief may include in that notice a compliance directive requiring the operator to take remedial action.~~

**4938. — Hearing on Notice of Probable Violation.**

~~(a) — If it requests a hearing in response to a notice of probable violation, an operator shall include in its request a written statement of the issues that it intends to raise at the hearing. The issues may include new information. Failure of the operator to specify an issue shall result in a waiver of that issue at the hearing unless, for good cause shown, the Commission permits the issue to be raised.~~

~~(b) — The hearing shall be held, and an order issued, in accordance with the Commission's Rules Regulating Practice and Procedure and Article 6 of Title 40, C.R.S.~~

~~(c) — The Commission may include in its order a civil penalty. If it includes a civil penalty, the order shall specify the amount of the penalty and the procedures for paying the penalty. The Commission may order a civil penalty only after considering the following:~~

~~(I) — The nature, circumstances, and gravity of the violation.~~

~~(II) — The operator's degree of culpability and its history of prior violations.~~

~~(III) — Any good faith efforts by the operator to remedy the violation or to prevent future similar violations.~~

- ~~(IV) — The size of the operator's business.~~
- ~~(V) — The operator's ability to pay the civil penalty and to continue in business after doing so.~~
- ~~(VI) — Any other matter in aggravation or in mitigation.~~
- ~~(d) — The Commission may include in its order a compliance directive. If the order includes a compliance directive, the order shall specify the actions to be taken by the operator and the time by which such actions must be completed.~~
- ~~(e) — The Commission may include in its order any other remedial action, requirement, or directive to ensure the public safety.~~

~~**4939. — Consent Stipulations.**~~

- ~~(a) — At any time before the issuance of a decision by the Commission, the Chief and the operator may agree to dispose of the matter by a consent stipulation, which shall be submitted to the Commission for approval or rejection.~~
- ~~(b) — A consent stipulation executed under this rule shall include the following:
  - ~~(I) — An admission by the operator of all jurisdictional facts.~~
  - ~~(II) — An express waiver by the operator of further procedural steps, including (without limitation) its right to a hearing; its right to seek judicial review or otherwise to challenge or to contest the validity of the consent stipulation; and its right to seek judicial review of the Commission order accepting the consent stipulation.~~
  - ~~(III) — An acknowledgment by the operator that the notice of probable violation may be used to construe the terms of the consent stipulation.~~
  - ~~(IV) — A statement of the actions which the operator will take and the date by which such actions shall be completed.~~~~
- ~~(c) — As appropriate, a consent stipulation executed under this rule may include a civil penalty.~~

~~**4940. — Hazardous Facilities Orders.**~~

- ~~(a) — After an inspection and/or a test, if the Chief is of the opinion that a pipeline facility or a LNG facility may be a hazardous facility, Staff may file a formal complaint with the Commission against the operator of the pipeline facility or the LNG facility. The complaint shall allege facts sufficient to establish the existence of a hazardous facility and to support a hazardous facility order. In an appropriate case and with the complaint, Staff may file a motion for an order pursuant to paragraph (j) of this rule.~~
- ~~(b) — A formal complaint by Staff shall be issued, and hearing shall be conducted, in accordance with the Commission's Rules Regulating Practice and Procedure and Article 6 of Title 40, C.R.S.~~

- ~~(c) — Except as provided in paragraph (j) of this rule, if the Commission finds, after hearing, that a pipeline facility or a LNG facility is hazardous to life or property, the Commission shall issue an order directing the operator to take corrective action. Corrective action may include, without limitation, suspension or restriction of the use of the pipeline facility or LNG facility, physical inspection, testing, repair, or replacement.~~
- ~~(d) — A pipeline facility or a LNG facility may be found to be a hazardous facility if the pipeline facility or a LNG facility has been constructed or operated with any equipment, material, or technique that is hazardous to life or property.~~
- ~~(e) — In making a determination that a pipeline facility or a LNG facility is hazardous to life or property, the following shall be considered, as appropriate:
  - ~~(I) — The characteristics of the pipe used in the pipeline facility or the LNG facility involved, including (without limitation) its age; manufacturer; physical properties, including its resistance to corrosion and deterioration; and the method of its manufacture, construction, or assembly.~~
  - ~~(II) — The nature of the gas transported by the pipeline facility or the LNG facility, including its corrosive and deteriorative qualities; the sequence in which the gas is transported; and the pressure required for transportation of the gas.~~
  - ~~(III) — The characteristics of the areas in which the pipeline facility or the LNG facility is located, in particular the climatic and geologic conditions (including soil characteristics) associated with the areas, the population, the population density, and the growth patterns of the areas.~~
  - ~~(IV) — Any recommendation of the National Transportation Safety Board issued in connection with any investigation conducted by that Board.~~
  - ~~(V) — Such other factors as may be relevant.~~~~
- ~~(f) — A Commission decision finding that a pipeline facility or a LNG facility is a hazardous facility shall contain the following:
  - ~~(I) — Findings of fact that form the basis for the conclusion that the pipeline facility or the LNG facility is hazardous to life or property.~~
  - ~~(II) — Conclusion that the pipeline facility or the LNG facility is a hazardous facility.~~
  - ~~(III) — Legal basis for the decision and order.~~
  - ~~(IV) — Description of the corrective action required of the operator.~~
  - ~~(V) — The date by which the operator shall complete the ordered corrective action.~~~~
- ~~(g) — The Commission shall dismiss the complaint if it determines that the pipeline facility or the LNG facility is not hazardous to life or property.~~



- ~~(h) — Upon a showing that the ordered corrective action has been completed and has eliminated the condition(s) which made a pipeline facility or a LNG facility hazardous to life or to property, the Commission shall issue an order of satisfaction. Prior to issuing an order of satisfaction, the Commission may hold a hearing to determine whether the operator has completed the corrective action and whether the corrective action has eliminated the condition(s) which made the pipeline facility or the LNG facility hazardous to life or property. The order of satisfaction shall be issued in the complaint docket in which the hazardous facilities order was entered.~~
- ~~(i) — Following issuance of an order of satisfaction, the Chief may issue a notice of probable violation pursuant to rule 4934.~~
- ~~(j) — If the Commission determines that the delay inherent in holding a hearing may result in, and significantly increases the likelihood of, serious harm to life or property, the Commission may issue a summary hazardous facilities order before holding a hearing. The provisions of paragraph (b) of this rule shall apply to a hearing held pursuant to this paragraph. The purpose of a hearing held pursuant to this paragraph is to determine whether the summary hazardous facilities order should remain in effect, should be amended, or should be rescinded. The summary hazardous facilities order shall include the following:~~
- ~~(I) — The findings which support the determination that a summary hazardous facilities order is appropriate.~~
- ~~(II) — The corrective or remedial actions required of the operator.~~
- ~~(III) — A statement informing the operator of its right to a hearing, upon request, as soon as practicable after issuance of the order.~~

**~~4941. — Injunctive Action.~~**

~~Whenever it appears to the Commission that an operator has engaged in, is engaging in, or is about to engage in any act or practice which constitutes a violation of 49 U.S.C. §§ 60101, et seq., these rules, an order of the Commission, or an order issued under these rules, the Commission may request that the Attorney General bring an action in a district court for an injunctive or other relief as provided in Article 7 of Title 40, C.R.S.~~

**~~4942. – 4949. — [Reserved].~~**

**~~Safety Standards for Gas Transportation by Pipeline and Gas Pipeline Systems~~**

**~~4950. — Compliance.~~**

~~An operator shall comply with these rules and the minimum safety standards for the transportation of natural gas and other gas by pipeline which are incorporated by reference in rule 4902(a).~~

**~~4951. — Conversion to Service.~~**

~~A pipeline previously used in service not subject to 49 C.F.R. Part 192 qualifies for service subject to 49 C.F.R. Part 192 if the operator prepares and follows a written procedure addressing the requirements of~~

~~49 C.F.R. § 192.14. The operator shall make its written procedures and applicable records available to Staff upon request.~~

~~**4952. Gathering Pipeline.**~~

- ~~(a) In addition to 49 C.F.R. § 192.9, all gathering pipeline operators must report underground facility damages to the Utility Notification Center of Colorado (UNCC-Colorado 811) “Colorado Damage Reporting Tool-DIRT” at <https://www.damagereporting.org/uncc>.~~
- ~~(b) Type A regulated gathering lines: An operator of metallic gathering lines where the MAOP produces a hoop stress of 20 percent or more of SMYS or non-metallic lines where the MAOP is more than 125 psig and located in a class 2, 3, or 4 location as defined in part § 192.5 shall follow the requirements of part 192 applicable to transmission pipelines, except the requirements in §192.150 and in subpart O of §192. However, an operator of a Type A gathering pipeline located in a class 2 location may demonstrate compliance with subpart N by describing the processes it uses to determine the qualifications of persons performing operation and maintenance tasks.~~
- ~~(c) Type B regulated gathering lines: An operator of metallic gathering lines where the MAOP produces a hoop stress less than 20 percent of SMYS or non-metallic lines and the MAOP is at 125 psig or less, and located in a class 2, 3, or 4 location as determined by using one of three methods found in part § 192.8, must comply with the following requirements:~~
- ~~(I) If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of part 192 applicable to transmission lines;~~
  - ~~(II) If the pipeline is metallic, control corrosion according to requirements of subpart I of part 192 applicable to transmission lines;~~
  - ~~(III) Carry out a damage prevention program under § 192.614;~~
  - ~~(IV) Establish a public education program under § 192.616;~~
  - ~~(IV) Establish the MAOP of the line under § 192.619;~~
  - ~~(IV) Install and maintain line markers according to the requirements for transmission lines in § 192.707;~~
  - ~~(IV) Carry out a leakage control program according to § 192.723(b);~~
  - ~~(IV) At a minimum, prepare a Procedural Manual addressing the above maintenance and operations items, and;~~
  - ~~(IV) Report any incident, or events as described in 4911(b), to Staff. Any hazardous leakage or conditions which may lead to a hazardous facility order shall be promptly repaired and documented.~~

- ~~(d) Type C gathering lines: An operator of gathering lines located in a class 1 location as defined in § 192.5 or type B gathering lines located in class 2 areas that the operator determines does not meet Area 2 dwelling density in §192.8, must comply with the following requirements:~~
- ~~(I) Telephonically report any incident, or events as described in 4911(b) to Staff. Any hazardous leakage or conditions which may lead to a safety threat to the public shall be promptly repaired and documented;~~
  - ~~(II) Tier 1 Member at the Utility Notification Center of Colorado if the pipeline system is located in any public road or railroad right-of-way, and;~~
  - ~~(III) Install and maintain pipeline markers at each crossing of a public road or railroad right-of-way, and labeled according to § 192.707(d).~~

#### **~~4953. Procedural Updates.~~**

~~As soon after the end of an incident, a safety-related condition, or an abnormal operating condition as defined in 49 C.F.R. § 192.803 as possible, each operator shall investigate, and shall make applicable changes to the operator qualification program, and the written procedural manual(s) used for conducting operations, for maintenance, and for emergencies. At a minimum, the operator shall review (and update, if necessary) applicable plans or procedural manual(s) at intervals not exceeding 15 months, but at least once each calendar year.~~

#### **~~4954. Amendment of Plans or Procedures.~~**

- ~~(a) If the Chief determines that an operator's plans or procedures required by rules 4900 through 4975 are inadequate to assure safe operation of a pipeline facility or a LNG facility, the Chief shall issue a notice of amendment to initiate a proceeding to determine whether the plans or procedures are inadequate. The notice of amendment shall:~~
- ~~(I) Provide an opportunity for a hearing pursuant to rule 4935.~~
  - ~~(II) Specify the alleged inadequacies and the proposed action for revision of the plans or procedures.~~
  - ~~(III) Allow the operator 30 days after receipt of the notice to submit written comments pursuant to rule 4935 or to request a hearing.~~
- ~~(b) In determining the adequacy of an operator's plans or procedures, the Chief shall consider the following:~~
- ~~(I) Relevant available pipeline safety data.~~
  - ~~(II) Whether the plans or procedures are appropriate for the particular type of pipeline transportation or facility and for the location of the facility.~~
  - ~~(III) The reasonableness of the plans or procedures.~~
  - ~~(IV) The extent to which the plans or procedures contribute to public safety.~~

~~(c) — Amendment of an operator’s plans or procedures as prescribed in paragraph (a) of this rule is in addition to, and may be used in conjunction with, other enforcement action.~~

~~4955. – 4959. — [Reserved].~~

**Safety Standards for Liquefied Natural Gas Facilities**

~~4960. — Compliance.~~

~~An operator shall comply with the safety standards for liquefied natural gas facilities which are incorporated by reference in rule 4902(b).~~

~~4961. – 4969. — [Reserved].~~

**Drug and Alcohol Testing**

~~4970. — Compliance.~~

~~An operator shall comply with the drug and alcohol testing program which is incorporated by reference in rule 4902(c) applicable to 49 C.F.R. Part 192 pipeline systems.~~

~~4971. – 4975. — [Reserved].~~

**4976. Regulated Gas Utility Rule Violations, Civil Enforcement, and Civil Penalties.**

An admission to or Commission adjudication for liability for an intentional violation of the following may result in the assessment of a civil penalty of up to \$2,000.00 per offense. Fines shall accumulate up to, but shall not exceed, the applicable statutory limits set in § 40-7-113.5, C.R.S.

Citation	Description	Maximum Penalty Per Violation
	Articles 1-7 of Title 40, C.R.S.	\$2000
	Commission Order	\$2000
Rule 4005	Records and Record Retention	\$2000
Rule 4027(a)	Collection and Use of Customer Data	\$1000
Rule 4027(b),	Disclosure of Customer Data	\$2000
Rule 4027(c)	Tariff	\$1000
Rule 4027(d)	Disclosure of Customer Data	\$1000

Rule 4028(a)	Customer Notice	\$1000
Rule 4029(a),(b)	Consent Form	\$1000
Rule 4030(a)	Disclosure of Customer Data	\$2000
Rule 4030(b)	Records	\$1000
Rule 4031(a)	Disclosure of Customer Data	\$2000
Rule 4031(b)	Records	\$1000
Rule 4032(a)	Disclosure of Customer Data	\$2000
Rules 4032(c) and (d)	Consent and Records	\$1000
Rule 4033(a)	Disclosure of Aggregated Data	\$2000
Rule 4033(d)	Tariff	\$1000
Rule 4100(a)	Obtaining a Certificate of Public Convenience and Necessity for a Franchise	\$2000
Rule 4101(a)	Obtaining a Certificate of Public Convenience and Necessity or Letter of Registration to operate in a service territory	\$2000
Rule 4102(a)	Obtaining a Certificate of Public Convenience and Necessity for facilities	\$2000
Rule 4103(a), (c), (d)	Amending a Certificate of Public Necessity for changes in service territory or facilities	\$2000
Rule 4108(a), (c)	Keeping a Current Tariff on File with the Commission	\$2000
Rule 4109	Filing a New or Changed Tariff with the Commission	\$2000
Rule 4110(b),(c)	Filing an Advice Letter to Implement a Tariff Change	\$2000
Rule 4200	Construction, Installation, Maintenance and Operation of Facilities in Compliance with Accepted Engineering and Industry Standards	\$2000

Rule 4208	Anticompetitive Conduct and Unacceptable Practices	\$2000
Rule 4210	Line Extensions	\$2000
Rule 4303	Meter Testing	\$2000
Rule 4306	Record Retention of Tests and Meters	\$2000
Rule 4309	Provision of Written Documentation of Readings and Identification of When Meters Will be Read	\$2000
Rule 4401	Billing Information, Procedures, and Requirements	\$2000
Rule 4754(a)-(e)	Annual DSM Report and Application for Bonus and Bonus Calculation	\$2000
Rule 4803(c)	Master Meter Exemption Requirements	\$2000
Rule 4004(b)-(f)	Disputes and Informal Complaints	\$1000
Rule 4202	Maintaining Heating Value, Purity and Pressure Standards	\$1000
Rule 4203(a)-(f)	Trouble Report Response, Interruptions and Curtailments of Service	\$1000
Rule 4405	Provision of Service, Rate, and Usage Information to Customers	\$1000
Rule 4406	Provision of Gas Cost Component Information to Customers	\$1000
Rule 4603(a),(d)	Gas Cost Adjustments	\$1000
Rule 4605(a),(b),(e),(f)	Gas Purchase Plans	\$1000
Rule 4607(a)	Gas Purchase Reports and Prudence Reviews	\$1000
Rule 4403(a)-(q)	Applications for Service, Customer Deposits, and Third Party Guarantees	\$500
Rule 4006	Annual Reporting Requirements	\$100

Rule 4304	Scheduled Meter Testing	\$100
Rule 4305	Meter Testing Upon Request	\$100
Rule 4402(a),(c),(d)	Meter and Billing Error Adjustments	\$100
Rule 4404(a)-(f)	Availability of Installation Payments to Customers	\$100
Rule 4407	Discontinuance of Service	\$100
Rule 4408(a)-(g); (i)	Notice of Discontinuation of Service	\$100
Rule 4409	Restoration of Service	\$100
Rule 4411(c)(IV),(d)(I), d(II),(e)	Low-Income Energy Assistance Act	\$100

**4977. – 4999. [Reserved].**

**GLOSSARY OF ACRONYMS.**

CAAM –	Cost Allocation and Assignment Manual
CCR –	Colorado Code of Regulations
C.F.R. –	Code of Federal Regulations
CPCN -	Certificate of Public Convenience and Necessity
CRCP –	Colorado Rules of Civil Procedure
C.R.S. -	Colorado Revised Statutes
<del>EAO –</del>	<del>Energy Assistance Organization</del>
e-mail -	Electronic mail
FDC -	Fully Distributed Cost
FERC –	Federal Energy Regulatory Commission
GAAP -	Generally Accepted Accounting Principles
GCA –	Gas Cost Adjustment
GPP –	Gas Purchase Plan
GPR –	Gas Purchase Report
ITP –	Intrastate Transmission Pipeline
LDC –	Local Distribution Company
<del>LNG –</del>	<del>Liquefied Natural Gas</del>
MMO –	Master Meter Operator
<del>NGA –</del>	<del>Natural Gas Act</del>
<del>OPS –</del>	<del>Office of Pipeline Safety (Federal DOT)</del>
OCC -	Office of Consumer Counsel
<del>PHMSA -</del>	<del>Pipeline and Hazardous Materials Safety Administration</del>

<del>P &amp; P</del>	<del>Practice and Procedure</del>
<del>SMYS</del>	<del>Specified Minimum Yield Strength</del>
<del>UNCC</del>	<del>Utility Notification Center of Colorado</del>
<del>U.S.C.</del>	<del>United States Code</del>
<del>U.S. DOT</del>	<del>United States Department of Transportation</del>
USOA –	Uniform System of Accounts

**Glossary of Gas Measurement Units:**

Btu –	British Thermal Unit
MMBtu –	1,000,000 Btu (approximately one Mcf, depending on heat content of gas)
Dth –	Dekatherm or One MMBtu
Therm –	100,000 Btu (approximately one Ccf, depending on heat content of gas)
Scf -	Standard cubic feet
Ccf –	100 cubic feet (typically actual cf at meter, rather than Scf)
Mcf –	1,000 standard cubic feet
MMcf –	1,000,000 standard cubic feet
Bcf –	1,000,000,000 standard cubic feet
MMcfd –	One MMcf per day



## **COLORADO DEPARTMENT OF REGULATORY AGENCIES**

### **Public Utilities Commission**

#### **4 CODE OF COLORADO REGULATIONS (CCR) 723-4**

#### **PART 4 RULES REGULATING GAS UTILITIES**

##### **BASIS, PURPOSE, AND STATUTORY AUTHORITY.**

The basis and purpose of these rules is to set forth rules describing the service to be provided by jurisdictional gas utilities and master meter operators to their customers and describing the manner of regulation over jurisdictional gas utilities, master meter operators, and the services they provide. These rules address a wide variety of subject areas including, but not limited to, service interruption, meter testing and accuracy, safety, customer information, customer deposits, rate schedules and tariffs, discontinuance of service, master meter operations, transportation service, flexible regulation, procedures for administering the Low-Income Energy Assistance Act, gas service low-income program, cost allocation between regulated and unregulated operations, recovery of gas costs, appeals regarding local government land use decisions, and authority of the Commission to impose civil penalties on public utilities. The statutory authority for these rules can be found at §§ 29-20-108, 40-1-103.5, 40-2-108, 40-3-102, 40-3-103, 40-3-104.3, 40-3-106, 40-3-111, 40-3-114, 40-3-101, 40-4-101, 40-4-106, 40-4-108, 40-4-109, 40-5-103, 40-7-117, 40-7-113.5, 40-7-116.5; and 40-8.7-105(5), C.R.S.

##### **GENERAL PROVISIONS**

##### **4000. Scope and Applicability.**

- (a) Absent a specific statute, rule, or Commission order which provides otherwise, all rules in this Part 4 (the 4000 series) shall apply to all jurisdictional gas utilities, gas master meter operators, and to all Commission proceedings concerning gas utilities and gas master meter operators.
- (b) The scope and applicability rules regarding appeals of local government land use decisions are as stated in rule 4700.

##### **4001. Definitions.**

The following definitions apply throughout this Part 4, except where a specific rule or statute provides otherwise. In addition to the definitions here, the definitions found in the Public Utilities Law and Part 1 apply to these rules. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply. In the event of a conflict between these definitions and a definition in Part 1, these definitions shall apply.

- (a) "Affiliate" of a utility means a subsidiary of a utility, a parent corporation of a utility, a joint venture organized as a separate corporation or partnership to the extent of the individual utility's

involvement with the joint venture, a subsidiary of a parent corporation of a utility or where the utility or the parent corporation has a controlling interest over an entity.

- (b) “Aggregated data” means customer data, alone or in combination with non-customer data, resulting from processing (e.g., average of a group of customers) and/or a compilation of customer data of one or more customers from which and personal information has been removed.
- (c) "Applicant for service" means a person who applies for utility service and who either has taken no previous utility service from that utility or has not taken utility service from that utility within the most recent 30 days.
- (d) "Basis Point" means one-hundredth of a percentage point (100 basis points = 1 percent).
- (e) "Benefit of service" means the use of utility service by each person of legal age who resides at a premises to which service is delivered and who is not registered with the utility as the customer of record.
- (f) "Commission" means the Colorado Public Utilities Commission.
- (g) “Contracted agent” means any person that has contracted with a utility in compliance with rule 4030 to assist in the provision of regulated utility services (e.g., an affiliate or vendor).
- (h) "Cubic foot" means, as the context requires:
  - (I) At Local Pressure Conditions. For the purpose of measuring gas to a customer at local pressure conditions, a cubic foot is that amount of gas which occupies a volume of one cubic foot under the conditions existing in the customer’s meter as and where installed. When gas is metered at a pressure in excess of eight inches of water column gauge pressure, a suitable correction factor shall be applied to provide for measurement of gas as if delivered and metered at a pressure of six inches of water column gauge pressure. A utility may also apply appropriate factors to correct local pressure measurement to standard conditions.
  - (II) At Standard Conditions. For all other purposes, including testing gas, a standard cubic foot is that amount of gas at standard conditions which occupies a volume of one cubic foot.
- (i) "Curtailment" means the inability of a transportation customer or a sales customer to receive gas due to a shortage of gas supply.
- (j) "Customer" means any person who is currently receiving utility service. Any person who moves within a utility’s service territory and obtains utility service at a new location within 30 days shall be considered a "customer." Unless stated in a particular rule, "customer" applies to any class of customer as defined by the Commission or by utility tariff.
- (k) “Customer data” means customer specific information, excluding personal information as defined in paragraph 1004(x), that is:

- (I) collected from the gas meter by the utility and stored in its data systems;
  - (II) combined with customer-specific energy usage information on bills issued to the customer for regulated utility service when not publicly or lawfully available to the general public; or
  - (III) about the customer's participation in regulated utility programs, such as renewable energy, demand-side management, load management, or energy efficiency programs.
- (l) "Dekatherm" (Dth) means a measurement of gas commodity heat content. One Dekatherm is the energy equivalent of 1,000,000 British Thermal Units (1 MMBtu).
  - (m) "Distribution system" means the piping and associated facilities used to deliver gas to customers, excluding facilities owned by a utility that are classified on the books and records of the utility as production, storage, or transmission facilities.
  - (n) "Energy assistance organization" means the nonprofit corporation established for low-income energy assistance pursuant to § 40-8.5-104, C.R.S.
  - (o) "Gas" means natural gas; flammable gas; manufactured gas; petroleum or other hydrocarbon gases including propane; or any mixture of gases produced, transmitted, distributed, or furnished by any utility.
  - (p) "Informal complaint" means an informal complaint as defined and discussed in the Commission's Rules Regulating Practice and Procedure.
  - (q) "Interruption" means a utility's inability to provide transportation to a transportation customer, or its inability to serve a sales customer, due to constraints on the utility's pipeline system.
  - (r) "Intrastate transmission pipeline" or "ITP" means generally any person that provides gas transportation service for compensation to or for another person in the State of Colorado using transmission facilities rather than distribution facilities and is exempt from FERC jurisdiction.
  - (s) "Local distribution company" (LDC) means any person, other than an interstate pipeline or an intrastate transmission pipeline, engaged in the sale and distribution of gas for end-user consumption. A LDC may also perform transportation services for its end-use customers, for another LDC and/or its end-use customers, as authorized under its effective Colorado jurisdictional tariffs.
  - (t) "Local government" means any Colorado county, municipality, city and county, home rule city or town, home rule city and county, or city or town operating under a territorial charter.
  - (u) "Local office" means any Colorado office operated by a utility at which persons may make requests to establish or to discontinue utility service. If the utility does not operate an office in Colorado, "local office" means any office operated by a utility at which persons may make requests to establish or to discontinue utility service in Colorado.
  - (v) "Main" means a distribution line that serves, or is designed to serve, as a common source of supply for more than one service lateral.

- (w) "Mcf" means 1,000 standard cubic feet.
- (x) "MMBtu" means 1,000,000 British Thermal Units, or one Dekatherm.
- (y) "Non-standard customer data" means all customer data that are not standard customer data.
- (z) "Past due" means the point at which a utility can affect a customer's account for regulated service due to non-payment of charges for regulated service.
- (aa) "Pipeline system" means the piping and associated facilities used in the transmission and/or distribution of gas.
- (bb) "Principal place of business" means the place, in or out of the State of Colorado, where the executive or managing principals who directly oversee the utility's operations in Colorado are located.
- (cc) "Property owner" means the legal owner of government record for a parcel of real property within the service territory of a utility. A utility may rely upon the records of a county clerk for the county within which a parcel of real property is located to determine ownership of government record.
- (dd) "Regulated charges" means charges billed by a utility to a customer if such charges are approved by the Commission, presented on a tariff sheet, and/or contained in a tariff of the utility.
- (ee) "Sales customer" means a person who receives sales service from a utility.
- (ff) "Sales service" means a bundled gas utility service in which the utility both purchases gas commodity for resale to the customer and delivers the gas to the customer.
- (gg) "Security" includes any stock, bond, note, or other evidence of indebtedness.
- (hh) "Service lateral" means that part of a distribution system from the utility's main to the entrance to a customer's physical location.
- (ii) "Standard conditions" means gas at a temperature of 60 degrees Fahrenheit and subject to an absolute pressure equal to 14.73 pounds per square inch absolute.
- (jj) "Standard customer data" means customer data maintained by a utility in its systems in the ordinary course of business.
- (kk) "Standby capacity" means the maximum daily volumetric amount of capacity reserved in the utility's system for use by a transportation customer, if the customer purchased optional standby service.
- (ll) "Standby supply" means the daily volumetric amount of gas reserved by a utility for the use by a transportation customer should that customer's supply fail, if the customer purchased optional standby service.

- (mm) "Third party" means a person who is not the customer, an agent of the customer who has been designated by the customer with the utility and is acting on the customer's behalf, a regulated utility serving the customer, or a contracted agent of the utility.
- (nn) "Transportation" means the exchange, forward-haul, backhaul, flow reversal, or displacement of gas between a utility and a transportation customer through a pipeline system.
- (oo) "Transportation customer" means a person who, by signing a gas transportation agreement, elects to subscribe to gas transportation service offered by a utility.
- (pp) "Unique identifier" means customer's name, mailing address, telephone number, or email address that is displayed on a bill.
- (qq) "Unregulated charges" means charges that are billed by a utility to a customer and that are not regulated or approved by the Commission, are not contained in a tariff, and are for service or merchandise not required as a condition of receiving regulated utility service.
- (rr) "Upstream pipeline" means either a natural gas pipeline or a LDC that provides gas to a LDC.
- (ss) "Utility" means a public utility as defined in § 40-1-103, C.R.S., providing sales service or transportation service (or both) in Colorado. This term includes both an ITP and a LDC.
- (tt) "Utility service" or "service" means a service offering of a utility, which service offering is regulated by the Commission.
- (uu) "Whole building data" means the sum of the monthly gas use for either all service connections at a building on a parcel of real property or all buildings on a parcel of real property.

**4002. Applications.**

- (a) Any person may seek Commission action regarding any of the following matters through the filing of an appropriate application to request a(n):
  - (I) issuance or extension of a certificate of public convenience and necessity for a franchise, as provided in rule 4100;
  - (II) issuance or extension of a certificate of public convenience and necessity for service territory, as provided in rule 4101;
  - (III) issuance of a certificate of public convenience and necessity for construction of facilities, as provided in rule 4102;
  - (IV) amendment of a certificate of public convenience and necessity to change, extend, curtail, abandon, or discontinue any service or facility, as provided in rule 4103;
  - (V) transfer a certificate of public convenience and necessity, to obtain a controlling interest in any utility, to transfer assets within the jurisdiction of the Commission or stock, or to merge a utility with another entity, as provided in rule 4104;

- (VI) approval of the issuance or assumption of any security, or to create a lien pursuant to § 40-1-104, as provided in rule 4105;
  - (VII) flexible regulatory treatment to provide service without reference to tariffs, as provided in rule 4106;
  - (VIII) amendment of a tariff on less than statutory notice, as provided in rule 4109;
  - (IX) approval of a meter sampling program, as provided in rule 4304;
  - (X) approval of a refund plan, as provided in rule 4410;
  - (XI) approval of a Low-Income Energy Assistance Plan, as provided in rule 4411;
  - (XII) approval of a cost assignment and allocation manual, as provided in rule 4503;
  - (XIII) appeal of a local government land use decision, as provided in rule 4703; or
  - (XIV) any other matter not specifically described in this rule, unless such matter is required to be submitted as a petition under rule 1304, as a motion, or as some other specific type of submittal.
- (b) In addition to the requirements of specific rules, all applications shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
- (I) the name and address of the applying utility;
  - (II) the name(s) under which the applying utility is, or will be, providing service in Colorado;
  - (III) the name, address, telephone number, and e-mail address of the applying utility's representative to whom all inquiries concerning the application should be made;
  - (IV) a statement that the applying utility agrees to answer all questions propounded by the Commission or Commission staff concerning the application;
  - (V) a statement that the applying utility shall permit the Commission or Commission staff to inspect the applying utility's books and records as part of the investigation into the application;
  - (VI) a statement that the applying utility understands that, if any portion of the application is found to be false or to contain material misrepresentations, any authorities granted pursuant to the application may be revoked upon Commission order;
  - (VII) in lieu of the separate statements required by subparagraphs (b)(IV) through (VI) of this rule, a utility may include a statement that it has read, and agrees to abide by, the provisions of subparagraphs (b)(IV) through (VI) of this rule;

- (VIII) a statement describing the applying utility's existing operations and general service area in Colorado.
  - (IX) for applications listed in subparagraphs (a)(I), (II), (III), (V), and (VI) of this rule, the applying utility's or parent company's and consolidated subsidiaries' most recent audited balance sheet, income statement, statement of retained earnings, and statement of cash flows so long as they provide Colorado specific financial information;
  - (X) a statement indicating the town or city, and any alternative town or city, in which the applying utility prefers any hearing be held; and
  - (XI) acknowledgment that, by signing the application, the applying utility understands that:
    - (A) the filing of the application does not by itself constitute approval of the application;
    - (B) if the application is granted, the applying utility shall not commence the requested action until the applying utility complies with applicable Commission rules and with any conditions established by Commission order granting the application; and
    - (C) if a hearing is held, the applying utility shall present evidence at the hearing to establish its qualifications to undertake, and its right to undertake, the requested action.
    - (D) in lieu of the statements contained in subparagraphs (b)(XI)(A) through (C) of this rule, an applying utility may include a statement that it has read, and agrees to abide by, the provisions of subparagraphs (b)(XI)(A) through (C) of this rule.
  - (XII) An attestation which is made under penalty of perjury; which is signed by an officer, a partner, an owner, an employee of, an agent for, or an attorney for the applying utility, as appropriate, who is authorized to act on behalf of the applying utility; and which states that the contents of the application are true, accurate, and correct. The application shall contain the title and the complete address of the affiant.
- (c) In addition to the requirements of specific rules, all applications shall include the information listed in subparagraphs (a)(I) through (V) of rule 1310. Applying utilities may either include the information in the application itself, or incorporate the information by reference to the most recent miscellaneous proceeding created under rule 1310.

- (d) Customer notice. Except as required or permitted by § 40-3-104, C.R.S., if the applicant is required by statute, Commission rule, or order to provide notice to its customers of the application, the applicant shall, within seven days after filing an application with the Commission, cause to have published notice of the filing of the application in each newspaper of general circulation in the municipalities impacted by the application. The applicant shall provide proof of such customer notice within 14 days of the publication in the newspaper. Failure to provide such notice or failure to provide the Commission with proof of notice may cause the Commission to deem the application incomplete. The applicant may also be required by statute, Commission rule, or order to provide additional notice to its customers of the application by first-class mailing or by hand-delivery. Both the newspaper notice and any additional customer notice(s) shall include the following:
- (I) the title “Notice of Application by [Name of the Utility] to [Purpose of Application]”;
  - (II) state that [Name of Utility] has applied to the Colorado Public Utilities Commission for approval to [Purpose of Application]. If the utility commonly uses another name when conducting business with its customers, the “also known as” name should also be identified in the notice to customers;
  - (III) provide a brief description of the proposal and the scope of the proposal, including an explanation of the possible impact upon persons receiving the notice;
  - (IV) identify which customer class(es) will be affected and the monthly customer rate impact by customer class, if customers’ rates are affected by the application;
  - (V) identify the proposed effective date of the application;
  - (VI) identify that the application was filed on less than statutory notice or if the applicant requests an expedited Commission decision, as applicable;
  - (VII) state that the filing is available for inspection in each local office of the applicant and at the Colorado Public Utilities Commission;
  - (VIII) identify the proceeding number, if known at the time the customer notice is provided;
  - (IX) state that any person may file written comment(s) or objection(s) concerning the application with the Commission. As part of this statement, the notice shall identify both the address and e-mail address of the Commission and shall state that the Commission will consider all written comments and objections submitted prior to the evidentiary hearing on the application;
  - (X) state that if a person desires to participate as a party in any proceeding before the Commission regarding the filing, such person shall file an intervention in accordance with the rule 1401 of the Commission’s Rules of Practice and Procedure or any applicable Commission order;



- (XI) state that the Commission may hold a public hearing in addition to an evidentiary hearing on the application and that if such a hearing is held members of the public may attend and make statements even if they did not file comments, objections or an intervention. State that if the application is uncontested or unopposed, the Commission may determine the matter without a hearing and without further notice; and
- (XII) state that any person desiring information regarding if and when hearings may be held shall submit a written request to the Commission or, alternatively, shall contact the External Affairs section of the Commission at its local or toll-free phone number. Such statement shall also identify both the local and toll-free phone numbers of the Commission's External Affairs section.

**4003. [Reserved].**

**4004. Disputes and Informal Complaints.**

- (a) For purposes of this rule, "dispute" means a concern, difficulty, or problem which needs resolution and which a customer or a person applying for service brings directly to the attention of the utility without the involvement of the Commission or Commission staff.
- (b) A dispute may be initiated orally or in writing. Using the procedures found in rule 1301, a utility shall conduct a full and prompt investigation of all disputes concerning utility service.
- (c) In accordance with the procedures in rule 1301, a utility shall conduct a full and prompt investigation of all informal complaints concerning utility service.
- (d) A utility shall comply with all rules regarding the timelines for responding to informal complaints.
- (e) If a current customer, or an applicant for service that is not a current customer, is dissatisfied with the utility's proposed adjustment or disposition of a dispute, the utility shall inform the person, customer or applicant for service of the right to make an informal complaint to the External Affairs section of the Commission and shall provide to the person, customer or applicant for service the address and toll free number of the Commission's External Affairs section.
- (f) A utility shall keep a record of each informal complaint and of each dispute. The record shall show the name and address of the initiating customer or person applying for service, the date and character of the issue, and the adjustment or disposition made. This record shall be open at all times to inspection by the person who initiated the informal complaint or dispute, by the Commission, and by Commission staff.

**4005. Records.**

- (a) Except as a specific rule may require, every utility shall maintain, for a period of not less than three years, and shall make available for inspection at its principal place of business during regular business hours, the following:
  - (I) records concerning disputes, which records are created pursuant to rule 4004;

- (II) complete records of tests to determine the heating value of gas, which records are created pursuant to rule 4202;
  - (III) records concerning interruptions and curtailments of service, which records are created pursuant to rule 4203;
  - (IV) transportation request logs, which records are created pursuant to paragraph 4205(e);
  - (V) notices of rejected transportation requests, which records are created pursuant to paragraph 4206(c);(VI) transportation agreements created pursuant to rule 4206;
  - (VII) all distribution pressure records, and all records or charts made with respect to rule 4208, appropriately annotated;
  - (VIII) meter calibration records created pursuant to under rule 4303;
  - (IX) records concerning meters, which records are created pursuant to rules 4305 and 4306;
  - (X) customer billing records, which records are created pursuant to paragraph 4401(a);
  - (XI) customer deposit records, which records are created pursuant to rule 4403;
  - (XII) records and supporting documentation concerning its cost assignment and allocation manual and fully-distributed cost study pursuant to paragraphs 4503(g) and 4504(e), for so long as the manual and study are in effect or are the subject of a complaint or a proceeding before the Commission;
  - (XIII) the total gas transported under each transportation service in Mcf or MMBtu and the associated total revenue;
  - (XIV) records concerning demand side management, pursuant to rules 4750 through 4760; and
  - (XV) as applicable, the records and documents required to be created pursuant to rules 4910 through 4920.
- (b) A utility shall maintain at each of its local offices and at its principal place of business all tariffs filed with the Commission and applying to Colorado rate areas. If the utility maintains a website, it shall also maintain its current and complete tariffs on its website.
- (c) A utility shall maintain its books of account and records in accordance with the provisions of 18 C.F.R. Part 201, the Uniform System of Accounts. A utility shall maintain its books of accounts and records separately and apart from those of its affiliates.
- (d) A utility shall preserve its records in accordance with the provisions of 18 C.F.R. Part 225, the Preservation of Records of Public Utilities and Licensees.

**4006. Reports.**

- (a) On or before April 30th of each year, a utility shall file with the Commission an annual report for the preceding calendar year. The utility shall submit the annual report on forms prescribed by the Commission; shall properly complete the forms; shall ensure the forms are verified and signed by a person authorized to act on behalf of the utility; and shall file in accordance with subparagraph 1204(a)(III) of the Commission's Rules of Practice and Procedure. If the Commission grants the utility an extension of time to file the annual report, the utility nevertheless shall file with the Commission, on or before April 30, the utility's total gross operating revenue from intrastate utility business transacted in Colorado for the preceding calendar year.
- (b) If a certified public accountant prepares an annual report for a utility, the utility shall file, within 30 days after the report is final, either two paper copies of the report with the Commission or an electronic copy through the Commission's E-Filing System.
- (c) On an annual basis, a utility shall file a report stating the average time taken for service personnel to respond to gas odor calls from customers for the following:
  - (I) the entire area served by the utility within Colorado; and
  - (II) each division of the utility assigned to serve a region or portion of the utility's entire service area.

**4007. [Reserved]**

**4008. Incorporation by Reference.**

- (a) The Commission incorporates by reference 18 C.F.R. Part 201 (as published on April 1, 2012) regarding the Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act. No later amendments to or editions of 18 C.F.R. Part 201 are incorporated into these rules.
- (b) The Commission incorporates by reference 18 C.F.R. Part 225 (as published on April 1, 2012) regarding the Preservation of Records of Natural Gas Companies. No later amendments to or editions of 18 C.F.R. Part 225 are incorporated into these rules.
- (c) Any material incorporated by reference in this Part 4 may be examined at the offices of the Commission, 1560 Broadway, Suite 250, Denver, Colorado 80202, during normal business hours, Monday through Friday, except when such days are state holidays. . Incorporated standards shall be available electronically and provided in certified copies, at cost, upon request. Restrictions on the provision of physical copies due to copyright protections may apply. The Director or the Director's designee will provide information regarding how the incorporated standards may be examined at any state public depository library. The standards and regulations are also available from the agency, organization or association originally issuing the code, standard, guideline or rule as follows: Code of Federal Regulations: [www.govinfo.gov/help/cfr](http://www.govinfo.gov/help/cfr).

## **CIVIL PENALTIES**

### **4009. Definitions.**

The following definitions apply to rules 4009, 4010, and 4976, unless a specific statute or rule provides otherwise. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- (a) “Civil penalty” means any monetary penalty levied against a public utility because of intentional violations of statutes in Articles 1 to 7 and 15 of Title 40, C.R.S., Commission rules, or Commission orders.
- (b) “Civil penalty assessment” means the act by the Commission of imposing a civil penalty against a public utility after the public utility has admitted liability or has been adjudicated by the Commission to be liable for intentional violations of statutes in Articles 1 to 7 and 15 of Title 40, C.R.S., Commission rules, or Commission orders.
- (c) “Civil penalty assessment notice” means the written document by which a public utility is given notice of an alleged intentional violation of statutes in Articles 1 to 7 and 15 of Title 40, C.R.S., Commission rules, or Commission orders and of a proposed civil penalty.
- (d) “Intentional violation.” A person acts “intentionally” or “with intent” when his conscious objective is to cause the specific result proscribed by the statute, rule, or order defining the violation.

### **4010. Regulated Gas Utility Violations, Civil Enforcement, and Enhancement of Civil Penalties.**

- (a) The Commission may impose a civil penalty in accordance with the requirements and procedures contained in § 40-7-113.5, C.R.S., § 40-7-116.5, C.R.S., and paragraph 1302(b), 4 Code of Colorado Regulations 723-1, for intentional violations of statutes in Articles 1 to 7 and 15 of Title 40, C.R.S., Commission rules, or Commission orders as specified in §§ 40-7-113.5 and 40-7-116.5, C.R.S., and in these rules.
- (b) The Director of the Commission or his or her designee shall have the authority to issue civil penalty assessments for the violations enumerated in § 40-7-113.5, C.R.S., subject to hearing before the Commission. When a public utility is cited for an alleged intentional violation, the public utility shall be given notice of the alleged violation in the form of a civil penalty assessment notice.
- (c) The public utility cited for an alleged intentional violation may either admit liability for the violation pursuant to § 40-7-116.5(1)(c) or the public utility may contest the alleged violation pursuant to § 40-7-116.5(1)(d), C.R.S. At any hearing contesting an alleged violation, trial staff shall have the burden of demonstrating a violation by a preponderance of the evidence.
- (d) In any written decision entered by the Commission pursuant to § 40-6-109, C.R.S., adjudicating a public utility liable for an intentional violation of a statute in Articles 1 to 7 and 15 of Title 40, C.R.S., a Commission rule, or a Commission order, the Commission may impose a civil penalty of not more than two thousand dollars, pursuant to § 40-7-113.5(1), C.R.S. In imposing any civil penalty pursuant to § 40-7-113.5(1), C.R.S., the Commission shall consider the factors set forth in Rule 1302(b).

- (e) The Commission may assess doubled or tripled civil penalties against any public utility, as provided by § 40-7-113.5(3), C.R.S., § 40-7-113.5(4), C.R.S., and this rule.
- (f) The Commission may assess any public utility a civil penalty containing doubled penalties only if:
  - (I) the public utility has admitted liability by paying the civil penalty assessment for, or has been adjudicated by the Commission in an administratively final written decision to be liable for, engaging in prior conduct that constituted an intentional violation of a statute in Articles 1 to 7 and 15 of Title 40, C.R.S., a Commission rule, or a Commission order;
  - (II) the conduct for which doubled civil penalties are sought violates the same statute, rule, or order as conduct for which the public utility has admitted liability by paying the civil penalty assessment, or conduct for which the public utility has been adjudicated by the Commission in an administratively final written decision to be liable; and
  - (III) the conduct for which doubled civil penalties are sought occurred within one year after conduct for which the public utility has admitted liability by paying the civil penalty assessment, or conduct for which the public utility has been adjudicated by the Commission in an administratively final written decision to be liable
- (g) The Commission may assess any public utility a civil penalty containing tripled penalties only if:
  - (I) the public utility has admitted liability by paying the civil penalty assessment for, or has been adjudicated by the Commission in an administratively final written decision to be liable for, engaging in prior conduct that constituted two or more prior intentional violations of a statute in Articles 1 to 7 and 15 of Title 40, C.R.S., a Commission rule, or a Commission order;
  - (II) the conduct for which tripled civil penalties are sought violates the same statute, rule, or order as conduct for which the public utility has either admitted liability by paying the civil penalty assessment or been adjudicated by the Commission in an administratively final written decision to be liable, in at least two prior instances; and
  - (III) the conduct for which tripled civil penalties are sought occurred within one year after the two most recent prior instances of conduct for which the public utility has either admitted liability by paying the civil penalty assessment, or been adjudicated by the Commission in an administratively final written decision to be liable.
- (h) When more than two instances of prior conduct exist, the Commission shall only consider those instances occurring within one year prior to the date of such alleged conduct for which tripled civil penalties are sought.
- (i) Nothing in this rule shall preclude the assessment of tripled penalties when doubled and tripled penalties are sought in the same civil penalty assessment notice.
- (j) The Commission shall not issue a decision on doubled or tripled penalties until after the effective date of the administratively final Commission decision upon which the single civil penalty was based.

- (k) The civil penalty assessment notice shall contain the maximum penalty amount provided by rule for each individual violation noted, with a separate provision for a reduced penalty of 50 percent of the penalty amount sought if paid within ten days of the public utility's receipt of the civil penalty assessment notice.
- (l) The civil penalty assessment notice shall contain the maximum amount of the penalty surcharge pursuant to § 24-34-108(2), C.R.S., if any.
- (m) A penalty surcharge referred to in paragraph (l) of this rule shall be equal to the percentage set by the Department of Regulatory Agencies on an annual basis. The surcharge shall not be included in the calculation of the statutory limits set in § 40-7-113.5(5), C.R.S.
- (n) Nothing in these rules shall affect the Commission's ability to pursue other remedies in lieu of issuing civil penalties.

**4011. – 4024. [Reserved].**

**CUSTOMER DATA ACCESS AND PRIVACY**

**4025. Scope and Applicability.**

- (a) The basis and purpose of these rules is to describe the protection of and limited access to customer data for gas utilities over which the Commission has jurisdiction. These rules are applicable to all utilities except for certain provisions as defined in the rule.
- (b) For the purpose of the Customer Data Access and Privacy Rules, gas utilities are classed into three tiers: a Tier I utility serves more than 150,000 gas customers; a Tier II utility serves between 50,000 and 150,000 gas customers. A Tier III utility serves fewer than 50,000 gas customers.
- (c) No Tier III utility is required to:
  - (I) include in its tariffs a description of standard and non-standard customer data that the utility is able to provide to the customer or to any third party recipient (see paragraph 4027(c));
  - (II) provide customer notice each year regarding customer data (see rule 4028);
  - (III) make customer consent forms for the disclosure of customer data available to customers or third parties (see rule 4029);
  - (IV) disclose aggregated data (see rule 4033); or
  - (V) provide a community energy report (see rule 4035).

However, a Tier III utility may include a description of standard and non-standard customer data that the utility is able to provide to the customer or to any third-party recipient in its tariffs (in accordance with paragraph 4027(c)). Commencing upon the effective date of such description, the Tier III utility shall be deemed to be a Tier II utility for purposes of these Customer Data Access and Privacy Rules for so long as such tariff provisions remain in effect.

**4026. Customer Data.**

- (a) A utility shall maintain standard customer data sufficient to allow a customer to understand his or her energy usage at a level of detail commensurate with the metering technology used to serve the customer.

**4027. Privacy, Access, and Disclosure.**

- (a) A utility shall protect customer data in the utility's possession or control to maintain the privacy of customers, while providing reasonable access to that data. A utility is only authorized to use customer data to provide regulated utility service in the ordinary course of business.
- (b) A utility shall not disclose customer data unless such disclosure conforms to these rules, except as required by law or to comply with Commission rule. Illustratively, this includes responses to requests of the Commission, warrants, subpoenas, court orders, or as authorized by § 16-15.5-102, C.R.S.
- (c) A utility shall include in its tariffs a description of customer data that the utility is able to provide to the customer or to any third party recipient to whom the customer has authorized disclosure of the customer's data within the utility's technological and data capabilities. At a minimum, the utility's tariff must provide the following:
  - (I) a description of standard customer data and non-standard customer data and the frequency of customer data updates that will be available (annual, monthly, daily, etc.);
  - (II) the method and frequency of customer data transmittal and access available (electronic, paper, etc.) as well as the security protections or requirements for such transmittal;
  - (III) a timeframe for processing requests;
  - (IV) any rate associated with processing a request for non-standard customer data; and
  - (V) any charges associated with obtaining non-standard customer data.
- (d) As part of basic utility service, a utility shall provide access to the customer's standard customer data in electronic machine-readable form, without additional charge, to the customer or to any third party recipient to whom the customer has authorized disclosure of the customer's customer data. Such access shall conform to nationally recognized open standards and best practices. The utility shall provide access in a manner that ensures adequate protections for the utility's system security and the continued privacy of the customer data during transmission.
- (e) Nothing in these rules shall limit a customer's right to provide his or her customer data to anyone.

- (f) A utility and each of its directors, officers and employees that discloses customer data pursuant to a customer's authorization in accordance with these data privacy rules shall not be liable or responsible for any claims for loss or damages resulting from the utility's disclosure of customer data.

**4028. Customer Notice.**

- (a) A utility shall provide each year to its customers a written notice complying with this rule. The utility shall conspicuously post on its website notice of its privacy and security policies governing access to and disclosure of customer data and aggregated data to third-parties. This notice shall:
- (I) explain what is available to customers, as standard and/or non-standard customer data (e.g., daily versus hourly data);
  - (II) describe the frequency that the utility can provide customer data based on a request for standard data (e.g., on a weekly or monthly basis);
  - (III) advise customers that their customer data may provide insight into their activities within the premises receiving service;
  - (IV) inform customers that the privacy and security of their customer data will be protected by the utility while in its possession;
  - (V) explain that customers can access their standard customer data, as identified by the utility's tariff, without additional charge;
  - (VI) advise customers that their customer data will not be disclosed to third parties, except:
    - (A) as necessary to provide regulated utility services to the customers;
    - (B) as otherwise permitted or required by law or Commission rule; or
    - (C) pursuant to the authorization given by the customer in accordance with these rules.
  - (VII) describe the utility's policies regarding how a customer can authorize access and disclosure of their customer data to third-parties. With regard to such third party data disclosure, the notice shall:
    - (A) inform customers that declining a request for disclosure of customer data to a third party will not affect the provision of utility service that the customer receives from the utility; and
    - (B) explain that any customer consent for access to, disclosure of, or use of a customer's customer data by a third party may be terminated or limited by the customer of record at any time and inform the customers of the process for doing so.



- (VIII) explain that aggregated data does not contain customer identifying information and inform customers that customer data may be used to create aggregated data that will not contain customer identifying information;
- (IX) explain that the utility may provide aggregated data to third-parties, subject to its obligation under paragraph 4033(a);
- (X) be viewable on-line and printed in ten point or larger font;
- (XI) be sent either separately or included as an insert in a regular monthly bill, or, for those customers who have consented to receive e-bills, such notice may be sent electronically separately from an e-bill, conspicuously marked and stating clearly that important information on the utility's privacy practices is contained therein;
- (XII) be available in English and Spanish. The customer notice may also be translated to a language other than English or Spanish by a third party or the utility. Forms translated to other languages in accordance with this rule must be accepted by utilities, and may be relied upon, after the English version of the form, the translated version of the form, and an affidavit attesting to the accurate and complete translation from the English version of the form, have been provided to the Commission and the utility possessing the data. Such affidavit must be executed by an interpreter on the active roster of interpreters maintained by the Office of Language Access of the Colorado Judicial Branch. If the utility incurs a cost for translation made at the request of a third party, it may charge the requestor for such cost and may include a reasonable administrative fee in addition to the translation cost; and
- (XIII) provide a customer service phone number and web address where customers can direct additional questions or obtain additional information regarding their customer data, the disclosure of customer data or aggregated data, or the utility's privacy policies and procedures with respect to customer data or aggregated data.

**4029. Customer Consent Form for the Disclosure of their Customer Data to Third Party Recipients by a Utility.**

- (a) A utility shall make available to any third party a consent form for the disclosure of customer data that is maintained by the Commission and available from the Commission's website. The form shall be available electronically from the utility. The consent form shall be provided in a non-electronic format by a utility upon request from a customer or third party.
- (b) In addition to the Commission supplied form, a utility may create and make available a consent form that:
  - (I) includes the same information contained in the annual notice provided under subparagraphs 4028(a)(V), (VI), (VII), and (XIII);
  - (II) provides spaces for the following required information regarding the third party recipient of the customer data:

- (A) the name, including trade name if applicable, physical address, mailing address, e-mail address, and telephone number;
  - (B) the uses of the data for which the customer is allowing disclosure;
  - (C) the time period (e.g., months, years) for which data are being requested; and
  - (D) the description of the data that are being requested;
- (III) states that the consent is valid until terminated;
- (IV) states that the customer must notify the utility service provider in writing (electronically or non-electronically) to terminate the consent including appropriate utility contact information;
- (V) states any additional terms except an inducement for the customer's disclosure;
- (VI) be viewable on-line and printed in ten point or larger font; and
- (VII) provides notice to the customer that the utility shall not be responsible for monitoring or taking any steps to ensure that the third party to whom the data is disclosed is maintaining the confidentiality of the data or using the data as intended by the customer.
- (c) A utility may make available an electronic customer consent process for disclosure of customer data to a third party (e.g., a utility controlled web portal) that authenticates the customer identity. The contents of the electronic consent process must generally follow the format of the model consent to disclose customer data form, be clear, and include the elements to be provided pursuant to paragraph (a) of this rule. No utility is required to provide an electronic consent process in a language other than English.
- (d) A utility may make available an in-person consent process for disclosure of customer data.
- (e) A consent form may be submitted to the utility through electronic or non-electronic methods.
- (f) The scope of consent given shall be defined by the terms of the consent form, except that changes of contact names for an organization, trade name, or utility over time do not invalidate consent as to the respective organization, trade name, or utility. Because the contact named for an organization, trade name, or utility is a representative of the respective organization, trade name, or utility, consent terminates as to such contact when the relationship with the organization, trade name, or utility terminates. Modifications to the consent form over time do not invalidate previous consent. Consent need not be provided on a new form so long as the data provided remains within the scope of consent.
- (g) Customer consent forms shall be available in English and Spanish. Customer consent forms may be translated to into languages other than English or Spanish by a third party or the utility. Forms translated to other languages in accordance with this rule must be accepted by utilities, and may be relied upon, after the English version of the form, the translated version of the form, and an affidavit attesting to the accurate and complete translation from the English version of the form, have been provided to the Commission and the utility possessing the data. Such affidavit must

be signed by an interpreter on the active roster of interpreters maintained by the Office of Language Access of the Colorado Judicial Branch. If a utility incurs a cost for a translation at the request of a third party, it may charge the requestor for such cost and may include a reasonable administrative fee in addition to the translation cost.

- (h) Any customer consent forms available from the Commission's website shall be presumed to comply with these rules.

**4030. Access to Customer Data for the Provision of Regulated Utility Service.**

- (a) A utility may disclose customer data to a contracted agent provided that the contract requires the agent to:
  - (I) implement and maintain data security procedures and practices to protect the customer data from unauthorized access, destruction, use, modification, or disclosure that are equal to or greater than the data privacy and security policies and procedures used by the utility internally to protect customer data;
  - (II) use customer data solely for the purpose of the contract and prohibits the use of customer data for a secondary commercial purpose not related to the purpose of the contract without first obtaining the customer's consent as provided for in these rules;
  - (III) return to the utility or destroy any customer data that is no longer necessary for the purpose for which it was transferred; and
  - (IV) execute a non-disclosure agreement with the utility.
- (b) The utility shall maintain records of the disclosure of customer data to contracted agents for a minimum of three years. Such records shall include all contracts with the contracted agent and executed non-disclosure agreements.

**4031. Local Government Access to Customer Data from a Utility for Audit.**

- (a) A utility may disclose customer data to a local government either with an audit required to be provided pursuant to a final Commission decision (e.g., a decision approving a franchise agreement) or as reasonably necessary for an audit conducted by a governmental entity of franchise fees paid to them by the utility, provided that:
  - (I) disclosure is not otherwise prohibited by a final Commission decision (e.g., Commission-approved franchise between the utility and the local government);
  - (II) disclosure is made to a designated auditor or auditor's office, who is either an employee or agent of the local government;
  - (III) the auditor collects and uses the customer data solely for the purpose of reviewing or conducting the audit and is prohibited from disclosing or using the customer data for a purpose not related to the audit;

- (IV) the local government implements and maintains data security procedures and practices to protect the customer data from unauthorized access, destruction, use, or modification;
  - (V) the local government destroys or returns to the utility of any customer data no longer necessary for the purpose for which it was transferred unless state law or the municipality's state-mandated retention schedule requires otherwise;
  - (VI) the local government agrees not to permit access to the data by anyone that has not agreed to abide by the terms pursuant to which the data was provided by the utility. This includes, but is not limited to, all interns, subcontractors, staff, other workforce members, and consultants;
  - (VII) the local government agrees that any recipient of the data pursuant to this rule does not obtain any right, title or interest in any of the data provided by the utility;
  - (VIII) governing law or a non-disclosure agreement executed with the utility requires that the local government, at a minimum, comply with the requirements of this rule; and
  - (IX) the data requested is for utility customers served in the boundaries of the local government.
- (b) The utility shall maintain records of all disclosures of customer data to local government requestors for a minimum of three years.
- (c) Availability of customer data pursuant to this rule does not preclude a local government from requesting other data reports.

**4032. Third Party Access to Customer Data from a Utility.**

- (a) Except as provided in this rule, paragraph 4027(b), rule 4030, and rule 4031, a utility shall not disclose customer data to any third party unless the customer or a third party acting on behalf of a customer submits a paper or electronic signed consent to disclose customer data form that has been executed by the customer of record.
- (b) Incomplete or non-compliant consent to disclose customer data forms are not valid and shall be rejected by the utility.
- (c) The utility shall maintain records of all of the disclosures of customer data to third party requestors. Such records shall include a copy of the customer's signed consent to disclose customer data form, all identifying documentation produced by the third party requestor, the customer's agreed upon terms of use, the date(s) and frequency of disclosure, and a description of the customer data disclosed.
- (d) The utility shall maintain records of customer data disclosures for a minimum of three years and shall make the records of the disclosure of a customer's customer data available for review by the customer within five business days of receiving a paper or electronic request from the customer, or at such greater time as is mutually agreed between the utility and the customer.

**4033. Requests for Aggregated Data Reports from a Utility.**

- (a) A utility shall not disclose aggregated data unless the recipient is authorized to receive all customer data within the aggregated data, and the disclosure otherwise conforms to this rule and rules 4031, 4034, and 4035. In aggregating customer data to create an aggregated data report, a utility must ensure that the data do not include any personal information or a unique identifier.
- (b) At a minimum, a particular aggregation must contain at least fifteen customers; and, within any customer class no single customer's customer data or premise associated with a single customer's customer data may comprise 15 percent or more of the total customer data aggregated per customer class to generate the aggregated data report (the "15/15 Rule").
- (c) If an aggregated data report cannot be generated in compliance with paragraph 4033(b), the utility shall notify the requestor that the aggregated data, as requested, cannot be disclosed and identify the reason(s) the request was denied. The requestor shall be given an opportunity to revise its aggregated data request in order to address the identified reason(s). An aggregated data request may be revised by expanding the number of customers or premise accounts in the request, expanding the geographic area included in the request, combining different customer classes or rate categories, or other applicable means of aggregating.
- (d) A utility shall include in its tariffs a description of standard and non-standard aggregated data reports available from the utility to any requestor. At a minimum, the utility's tariff shall provide the following:
  - (I) a description of standard and non-standard aggregated data reports available from the utility including all available selection parameters (customer data or other data);
  - (II) the frequency of data collection (annual, monthly, daily, etc.);
  - (III) the method of transmittal available (electronic, paper, etc.) and the security protections or requirements for such transmittal;
  - (IV) the charge for providing a standard aggregated data report or the hourly charge for compiling a non-standard aggregated data report;
  - (V) the timeframe for processing requests; and
  - (VI) a request form for submitting a data request for aggregated data reports to the utility identifying any information necessary from the requestor in order for the utility to process the request.
- (e) If a utility is unable to fulfill a non-standard aggregated data report request because it does not have and/or does not elect to or cannot obtain all of the data the requestor wishes to include in the aggregated data report, then the utility may contract with a contracted agent to include the additional data and process it along with the customer data in the utility's possession, to generate a non-standard aggregated data report.

- (f) A utility and each of its directors, officers and employees that discloses aggregated data as provided in these data privacy rules shall not be liable or responsible for any claims for loss or damages resulting from the utility's disclosure of aggregated data.
- (g) A utility shall not provide aggregated customer data in response to multiple overlapping requests from or on behalf of the same requestor that have the potential to identify customer data.

**4034. Property Owner Request for Whole Building Energy Use Data from a Utility.**

- (a) If requested by a property owner or its authorized agent, a Tier I utility shall provide whole building energy use data to the property owner or its authorized agent so long as:
  - (I) the whole building energy use data contains at least four customers or tenants, which may include the property owner's own account; and no single customer's customer data, unless it is the property owner's, comprises more than 50 percent of the whole building energy use data used to generate the whole building energy use data report;
  - (II) the property owner or its authorized agent agrees to not disclose the whole building energy use data except for the purposes of building benchmarking, identifying energy efficiency projects, and energy management; and
  - (III) the property owner or its authorized agent signs a non-disclosure agreement with the utility requiring the property owner, at a minimum to:
    - (A) take appropriate administrative, technical, and physical safeguards to protect the whole building data from any unauthorized use or disclosure to protect the data from unauthorized access, destruction, use, modification, or disclosure;
    - (B) only use the whole building data only for the purposes of building benchmarking, identifying energy efficiency projects, energy management, and complying with laws or ordinances;
    - (C) agree not to attempt to determine an individual utility customer's energy use from the whole building data and not to use the information to contact the subject of the information;
    - (D) agree not to use the whole building energy use data for a secondary commercial purpose not related to the authorized purpose without first obtaining the customer's consent as provided for in these rules;
    - (E) destroy any whole building energy use data that is no longer necessary for the purpose for which it was transferred;
    - (F) agree not to permit access to the whole building data by anyone that has not agreed to abide by the terms pursuant to which the data was provided by the utility. This includes, but is not limited to, all interns, subcontractors, staff, other workforce members, and consultants; and

- (G) agree that any recipient of the whole building data pursuant to this rule does not obtain any right, title or interest in any of the data provided by the utility.
- (b) Upon request by a property owner or its authorized agent, a Tier II utility shall provide whole building energy use data upon the same conditions to the extent of, and based upon, information available in the ordinary course of business.
- (c) A utility shall provide a requested whole building energy use data report in electronic, machine readable format that conforms to nationally recognized open standards and best practices.
- (d) A utility may charge a property owner or its authorized agent for the development of a whole building energy use data report. Such rate shall be determined in a utility tariff as a non-standard aggregated data report. Alternatively, the utility need not charge the customer if the cost to charge a property owner or its authorized agent is greater than the cost to develop a whole building energy use data report.
- (e) Availability of whole building energy use data pursuant to this rule does not preclude a property owner from requesting other data reports.

**4035. Community Energy Reports.**

- (a) A Tier I utility shall generate a community energy report for each local government other than a Colorado county included in its service territory with 50,000 or more residents. A Tier I utility shall generate a community energy report for each Colorado county included in its service territory with 100,000 or more residents. Any local government with fewer than 50,000 residents and Colorado county with fewer than 100,000 residents or a minority of whom are served by a Tier I utility shall be treated as if it had 50,000 or more residents served by the Tier I upon request from the local government or county. Such requests shall be made by January 31 of the calendar year following the reporting year and shall continue in effect until such time as the request is withdrawn or cancelled by the local government. All population thresholds shall be based on the most recent population estimate from the Colorado State Demography Office and where the utility serves the majority of the population.
- (b) On or before June 1 of every year, a Tier I utility shall make publicly available for download all community energy reports generated for the prior year. Reports shall be available in an electronic machine-readable form that conforms to nationally recognized open standards and best practices.
- (c) The community energy report shall include the following information and aggregated data for the utility and its customers and specific to the local government for the prior calendar year:
  - (I) the annual dekatherms consumed by customers, provided by residential, commercial, and industrial classes;
  - (II) the average number of customers in the residential, commercial, and industrial class; and
  - (III) the total annual energy saved (in dekatherms) from energy efficiency measures installed.

- (d) A local government may submit, or have another local government submit on its behalf, a GIS data to define its jurisdictional boundaries prior to the issuance of the community energy report.
- (e) Upon request by a local government, a Tier II utility shall generate a community energy report, in accordance with this rule, consistent with the utility's meter, network, or data capabilities. Such requests shall be made by January 31 of the calendar year following the reporting year and shall continue in effect until such time as the request is withdrawn or cancelled by the local government. On or before June 1 of every year, the utility shall make publicly available for download all community energy reports generated for the prior year. Reports shall be available in an electronic machine-readable form that conforms to nationally recognized open standards and best practices.
- (f) Availability of the community energy report pursuant to this rule does not preclude a local government from requesting other data reports.

**4036.– 4099. [Reserved].**

## **OPERATING AUTHORITY**

### **4100. Certificate of Public Convenience and Necessity for a Franchise.**

- (a) A utility seeking authority to provide service pursuant to a franchise shall file an application pursuant to this rule. When a utility enters into a franchise agreement with a municipality for the first time, it shall obtain authority from the Commission pursuant to § 40-5-102, C.R.S. prior to providing service under that initial franchise agreement. A utility maintains the right and obligation to serve a municipality within its service territory after the expiration of any franchise agreement.
- (b) An application for certificate of public convenience and necessity to exercise franchise rights shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) the information required in paragraphs 4002(b) and 4002(c);
  - (II) a statement of the facts (not conclusory statements) relied upon by the applying utility to show that the public convenience and necessity require the granting of the application;
  - (III) a statement describing the franchise rights proposed to be exercised. The statement shall include a description of the type of utility service to be rendered and a description of the city or town sought to be served;
  - (IV) a certified copy of the franchise ordinance; proof of publication, adoption, and acceptance by the applying utility; a statement as to the number of customers served or to be served and the population of the city or town; and any other pertinent information;
  - (V) a statement describing in detail the extent to which the applying utility is an affiliate of any other utility which holds authority duplicating in any respect the authority sought;



- (VI) the feasibility study for areas previously not served by the applying utility, which study shall at least include estimated investment, income, and expense. An applying utility may request that its most recent audited balance sheet, income statement, statement of retained earnings, and statement of cash flows be submitted in lieu of a feasibility study; and
- (VII) a statement of the names of public utilities and other entities of like character providing similar service in or near the area sought to be served.

**4101. Certificate of Public Convenience and Necessity for Service Territory.**

- (a) A utility seeking authority to provide service in a new service territory shall file an application pursuant to this rule. A utility cannot provide service to a new geographic area without authority from the Commission, unless the utility extends its facilities and service:
  - (I) within a city and county or city or town within which the utility has lawfully commenced operations;
  - (II) into territory contiguous to the utility's facility, line, plant, or system that is not served by a public utility providing the same commodity or service; or
  - (III) within or to territory already served by the utility and the extension is necessary in the ordinary course of business.
- (b) An application for certificate of public convenience and necessity to provide service in a new territory shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) the information required in paragraphs 4002(b) and 4002(c);
  - (II) a statement of the facts (not conclusory statements) relied upon by the applying utility to show that the public convenience and necessity require the granting of the application;
  - (III) a description of the type of utility service to be rendered and a description of the area sought to be served;
  - (IV) a map showing the specific geographic area that the applying utility proposes to serve. If the applying utility intends to phase in service in the territory over time, specific areas and proposed in-service dates shall be included. The map shall describe the geographic areas in section, township, and range convention;
  - (V) a statement describing in detail the extent to which the applying utility is an affiliate of any other utility which holds authority duplicating in any respect the territory sought;
  - (VI) a statement of the names of public utilities and other entities of like character providing similar service in or near the area involved in the application;

- (VII) a feasibility study for the proposed area to be served, which shall at least include estimated investment, income, and expense. An applying utility may request that its most recent audited balance sheet, income statement, statement of retained earnings, and statement of cash flows be submitted in lieu of a feasibility study; and
- (VIII) a statement of the names of public utilities and other entities of like character providing similar service in or near the area sought to be served.

**4102. Certificate of Public Convenience and Necessity for Facilities.**

- (a) A utility seeking authority to construct and to operate a facility or an extension of a facility pursuant to § 40-5-101, C.R.S., shall file an application pursuant to this rule. The utility need not apply to the Commission for approval of construction and operation of a facility or an extension of a facility which is in the ordinary course of business. The utility shall apply to the Commission for approval of construction and operation of a facility or an extension of a facility which is not in the ordinary course of business.
- (b) An application for certificate of public convenience and necessity to construct and to operate facilities or an extension of a facility pursuant to § 40-5-101, C.R.S., shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) the information required in paragraphs 4002(b) and 4002(c);
  - (II) a statement of the facts (not conclusory statements) relied upon by the applying utility to show that the public convenience and necessity require the granting of the application or citation to any Commission decision that is relevant to the proposed facilities;
  - (III) a description of the proposed facilities to be constructed;
  - (IV) estimated cost of the proposed facilities to be constructed;
  - (V) anticipated construction start date, construction period, and in-service date;
  - (VI) a map showing the general area or actual locations where facilities will be constructed, population centers, major highways, and county and state boundaries; and
  - (VII) as applicable, information on alternatives studied, costs for those alternatives, and criteria used to rank or eliminate alternatives.

**4103. Certificate Amendments for Changes in Service, in Service Territory, or in Facilities.**

- (a) A utility seeking authority to do the following shall file an application pursuant to this rule: amend a certificate of public convenience and necessity in order to extend, to restrict, to curtail, or to abandon or to discontinue without equivalent replacement any service, service area, or facility. A utility shall not extend, restrict, curtail, or abandon or discontinue without equivalent replacement any service, service area, or facility not in the ordinary course of business without authority from the Commission.

- (b) An application to amend a certificate of public convenience and necessity in order to change, to extend, to restrict, to curtail, to abandon, or to discontinue any service, service area, or facility without equivalent replacement shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) all information required in paragraphs 4002(b) and 4002(c);
  - (II) if the application for amendment pertains to a certificate of public convenience and necessity for facilities, all of the information required in rule 4102;
  - (III) if the application for amendment pertains to a certificate of public convenience and necessity for franchise rights, all of the information required in rule 4100;
  - (IV) if the application for amendment pertains to a certificate of public convenience and necessity for service territory, all of the information required in rule 4101;
  - (V) if the application for amendment pertains to a service, the application shall include:
    - (A) the requested effective date for the extension, restriction, curtailment, or abandonment or discontinuance without equivalent replacement of the service; and
    - (B) a description of the extension, restriction, curtailment, or abandonment or discontinuance without equivalent replacement sought. This shall include maps, as applicable. This shall also include a description of the applying utility's existing operations and general service area.
- (c) Customer notice of application. In addition to complying with the notice requirements of the Commission's Rules Regulating Practice and Procedure, a utility applying to curtail, restrict, abandon or discontinue service without equivalent replacement shall prepare a written notice as provided in subparagraphs 4002(d)(I) through (XII) and shall mail or deliver the notice at least 30 days before the application's requested effective date to each of the applying utility's affected customers. The customer notice shall include a statement detailing the requested restriction, curtailment, or abandonment or discontinuance without equivalent replacement.
- (d) If no customers will be affected by the grant of the application, the notice must meet the requirements of subparagraphs 4002(d)(I) through (XII) and shall be mailed to the Board of County Commissioners of each affected county, and to the mayor of each affected city, town, or municipality.

**4104. Transfers, Controlling Interest, and Mergers.**

- (a) A utility seeking authority to do any of the following shall file an application pursuant to this rule: transfer a certificate of public convenience and necessity; transfer or obtain a controlling interest in a utility, whether the transfer of control is effected by the transfer of assets, by the transfer of stock, by merger or by other form of business combination; or transfer assets subject to the jurisdiction of the Commission outside the normal course of business. A utility cannot transfer a certificate of public convenience and necessity; transfer or obtain a controlling interest in any

utility; or transfer assets outside the normal course of business without authority from the Commission.

- (b) An application to transfer a certificate of public convenience and necessity, to transfer or obtain a controlling interest in a utility, or to transfer assets subject to the jurisdiction of the Commission shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
- (I) the information required in paragraphs 4002(b) and 4002(c), as pertinent to each party to the transaction;
  - (II) a statement showing accounting entries, under the Uniform System of Accounts, including any plant acquisition adjustment, gain, or loss proposed on the books by each party before and after the transaction which is the subject of the application;
  - (III) any agreement for merger, sales agreement, or contract of sale pertinent to the transaction which is the subject of the application;
  - (IV) all facts showing that the transaction which is the subject of the application is not contrary to the public interest;
  - (V) an evaluation of the benefits and detriments to the customers of each party and to all other persons who will be affected by the transaction which is the subject of the application; and.
  - (VI) a comparison of the kinds and costs of service rendered before and after the transaction which is the subject of the application.
- (c) An application to transfer a certificate of public convenience and necessity, an application to transfer assets subject to the jurisdiction of the Commission, or an application to transfer or obtain control of the utility may be made by joint or separate application of the transferor and the transferee.
- (d) When control of a utility is transferred to another entity, or the utility's name is changed, the utility which will afterwards operate under the certificate of public convenience and necessity shall file with the Commission a tariff adoption notice, shall post the tariff adoption notice in a prominent public place in each local office and principal place of business of the utility, and shall have the tariff adoption notice available for public inspection at each local office and principal place of business. Adoption notice forms are available from the Commission. The tariff adoption notice shall contain all of the following information:
- (I) the name, phone number, and complete address of the adopting utility;
  - (II) the name of the previous utility;
  - (III) the number of the tariff adopted and the description or title of the tariff adopted;
  - (IV) the number of the tariff after adoption and the description or title of the tariff after adoption; and

- (V) unless otherwise requested by the applying utility in its application, a statement that the adopting utility is adopting as its own all rates, rules, terms, conditions, agreements, concurrences, instruments, and all other provisions that have been filed or adopted by the previous utility.

**4105. Securities and Liens.**

- (a) Subject to the exception contained in paragraph (h) of this rule, a utility which either derives more than five percent of its consolidated gross revenues in Colorado as a public utility or derives a lesser percentage if its revenues are earned by supplying an amount of energy which equals five percent or more of Colorado's consumption shall file an application for Commission approval of any proposal to issue or to assume any security or to create a lien.
- (b) An application for the issuance or assumption of securities with a maturity of 12 months or more or to create a lien shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) all information required in paragraphs 4002(b) and 4002(c);
  - (II) the resolution of the applying utility's board of directors approving the issuance, or assumption of the securities or to create a lien, together with, as applicable and available, the proposed indenture requirements, the mortgage note, the amendment to the loan contract, and the contract for sale of securities or creation of a lien;
  - (III) a statement describing each short-term and long-term indebtedness outstanding on the date of the most recent balance sheet;
  - (IV) a statement describing the classes and amounts of capital stock authorized by the articles of incorporation and the amount by each class of capital stock outstanding on the date of the most recent balance sheet;
  - (V) a statement of capital structure showing common equity, long-term debt, preferred stock, if any, and pro forma capital structure on the date of the most recent balance sheet giving effect to the issuance of the proposed securities. Debt and equity percentages to total capitalization, actual and pro forma, shall be shown;
  - (VI) a statement of the amount and rate of dividends declared and paid, or the amount and year of capital credits assigned and capital credits refunded, during the previous four calendar years including the present year to the date of the most recent balance sheet;
  - (VII) a statement describing the type and amount of securities to be issued; the anticipated interest rate or dividend rate; the redemption or sinking fund provisions, if any; and, within ten days of their filing with the Securities and Exchange Commission, the registration statement, related forms, and preliminary prospectus filed with the Securities and Exchange Commission relating to the proposed issuance;
  - (VIII) a statement of proposed uses, including construction, to which the funds will be or have been applied and a concise statement of the need for the funds; and

- (IX) a statement of the estimated cost of financing.
- (c) For applications for the creation of a lien on the applying utility's property situated within the State of Colorado where the creation of the lien is not related to the issuance or assumption of a security, the application shall also include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
- (I) a description of the property which will be subject to the lien;
  - (II) the amount of the lien;
  - (III) the proposed use of the funds to be received from the lien;
  - (IV) the estimated cost for the creation of the lien;
  - (V) the anticipated duration of the lien;
  - (VI) the anticipated release date of the lien;
  - (VII) the retirement payment plan to release the lien;
  - (VIII) a description of how the applying utility will ensure that neither the creation of the lien nor the use of the proceeds will violate § 40-3-114, C.R.S.;
  - (IX) a statement that, for the duration of the lien, the applying utility will advise the Commission within ten days of any bankruptcy, foreclosure, or liquidation proceeding; and
  - (X) a statement that the applying utility will advise the Commission within ten days of any deviation from its lien retirement payment plan;
- (d) The Commission shall issue notice of the application, which shall set a ten-day intervention period and a hearing date.
- (e) Customer notice. Within three days after the filing of an application to issue or to assume a security, the applying utility shall publish notice of the filing of the application in a newspaper of general circulation. The notice shall include, in addition to the information required by subparagraphs 4002(d)(I) – (XII), the address of the applicant.
- (f) The applying utility shall file with the Commission the published notice and an affidavit of publication as soon as possible after the filing of the application. The Commission shall not grant the application without the notice and the affidavit of publication.
- (g) The Commission shall give priority to an application made pursuant to this rule and shall grant or deny the application within 30 days after filing, unless the Commission, for good cause shown, enters an order granting an extension and stating fully the facts necessitating the extension. The Commission shall approve or disapprove an application made pursuant to this rule by written order.

- (h) Pursuant to § 40-1-104, C.R.S., a utility may issue, renew, extend or assume liability on securities, other than stocks, with a maturity date of not more than 12 months after the date of issuance, whether secured or unsecured, without application to or order of the Commission provided that no such securities so issued shall be refunded, in whole or in part, by any issue of securities having a maturity of more than 12 months except on application to and approval of the Commission.
- (i) Any security requiring Commission approval, but issued or assumed without such approval, shall be void.

**4106. Flexible Regulation to Provide Jurisdictional Service Without Reference to Tariffs.**

- (a) A utility seeking authority to provide a jurisdictional service without reference to a tariff shall file an application pursuant to this rule. A utility cannot provide a jurisdictional service without reference to a tariff without authority from the Commission.
- (b) An application for flexible regulation to provide jurisdictional service without reference to tariffs shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) all information required in paragraphs 4002(b) and 4002(c);
  - (II) the name of the customer or potential customer;
  - (III) a description of the jurisdictional service or services which the applying utility seeks to provide to a customer or a potential customer;
  - (IV) a description of the manner in which the applying utility will provide the jurisdictional service or services if it contracts with a customer or potential customer;
  - (V) the facts (not in conclusory form) which the applying utility believes satisfy the requirements of § 40-3-104.3(1)(a), C.R.S.; and
  - (VI) a statement that the applying utility has provided, or will provide when available, the application and contract as required by paragraph 4106(c) of this rule.
- (c) The contract which is the subject of the application shall be filed when available with the Commission under seal pursuant to rules 1100 through 1102 and § 40-3-104.3(1)(b), C.R.S. The applying utility shall furnish the application and, when it is available, the contract, under seal, to the OCC. Unless the applying utility requests other treatment, the Commission and the OCC shall treat the contract as confidential. If the Commission grants a protective order preserving the confidentiality of the contents of an application, then the applying utility shall also furnish a non-confidential version of the application without the contract to any utility then providing service to the customer or potential customer.

- (d) The direct testimony and attachments to be offered at hearing shall accompany the application unless the applying utility believes that the application will be uncontested and unopposed. If an attachment is large or cumbersome, the applying utility shall file the attachment with the Commission; shall provide, for the benefit of the intervenors, the title of the attachment and a summary of the information contained in the attachment; and shall state the location (other than the Commission) at which parties may inspect the attachment.
- (e) Pre-filed testimony or attachments shall not be modified once filed unless the modification is to correct typographical errors or misstatements of fact or unless all parties to the proceeding agree to the modification. In the event a substantive modification is made without the agreement of all parties, the Commission may allow the modification only upon a showing of good cause. The Commission may consider the effect of the substantive modification as a basis for a motion to continue in order to allow the Commission staff or any other party a reasonable opportunity to investigate and, if necessary, to address the modification.
- (f) The Commission shall provide notice of the application. Any person desiring to intervene in a proceeding initiated pursuant to § 40-3-104.3, C.R.S., and this rule shall move to do so within five days of the date the Commission provides notice.
- (g) Within five days of receiving written notice of an intervention in a proceeding initiated pursuant to § 40-3-104.3, C.R.S., and this rule, the applying utility shall hand-deliver or otherwise provide to the intervenor a non-confidential version of the application and the applying utility's pre-filed testimony and attachments.
- (h) Unless the Commission orders otherwise, the applying utility shall publish notice of the application in a newspaper of general circulation within three days of the filing of the application.
- (i) In addition to the requirements of subparagraphs 4002(d)(I) – (XII), the notice provided by the applying utility shall contain the following information:
  - (I) the address of the applying utility;
  - (II) the name of the customer(s) or potential customer(s) involved;
  - (III) a statement that the identified customer(s) or potential customer(s) may have the ability to provide its/their own service or may have competitive alternatives available to it/them;
  - (IV) a general description of the jurisdictional services to be provided;
  - (V) a statement of where affected customers may call to obtain information concerning the application and;
  - (VI) a statement that anyone desiring to participate as a party must file a petition to intervene within five days from the date of Commission notice of the application and that the intervention must comport with the Commission's Rules Regulating Practice and Procedure.
- (j) Within three days of providing notice, the applying utility shall file with the Commission an affidavit showing proof of publication of notice.



- (k) On a case-by-case basis, the Commission may require the applying utility to provide additional information.
- (l) Should an application be filed which the Commission determines is not complete, the Commission or Commission staff shall notify the applying utility within seven days from the date the application is filed of the need for additional information. The applying utility may then supplement the application so that it is complete. Once the application is complete, the Commission will process the application, with all applicable timelines running from the date the application is completed.
- (m) The Commission shall issue an order approving or disapproving the application within the time permitted under § 40-3-104.3(1)(b), C.R.S.
- (n) At the time of any proceeding in which a utility's overall rate levels are determined, the Commission may require the utility to file a fully distributed cost method which segregates investments, revenues, and expenses associated with jurisdictional utility service provided pursuant to any contract approved under this rule 4106 from other regulated utility operations in order to ensure that jurisdictional utility service provided pursuant to contract is not subsidized by revenues from other regulated utility operations.
- (o) The applying utility shall provide final contract or other description of the price and terms of service as specified in § 40-3-104.3(1)(e), C.R.S.

**4107. [Reserved].**

**4108. Tariffs.**

- (a) A utility shall keep on file with the Commission the following documents pertaining to gas sales service and gas transportation service: its current Colorado tariffs, forms of contracts (including gas sales agreements), and those gas transportation service agreements which are not the same as the standard gas transportation service agreement contained in the utility's tariffs. These documents, unless filed under seal, shall be available for public inspection at the Commission and at the principal place of business of the utility.
- (b) All tariffs shall comply with rule 1210 of the Commission's Rules of Practice and Procedure.
- (c) Filing and contents of tariff.
  - (l) In addition to the requirements and contents in rule 1210, the following shall be included in a utility's tariff as applicable:
    - (A) a description of the minimum heating value for gas service as required by paragraph 4202(a);
    - (B) a description of testing methods for gas quality as required by paragraph 4202(f);
    - (C) interruption and curtailment criteria, policies, and implementation priorities, as required by rule 4203;

- (D) transportation service rates, terms, and conditions, as required by rule 4205;
- (E) the utility's transportation service request form as required by paragraph 4206(a);
- (F) information regarding the utility's meter testing equipment and facilities, scheduled meter testing, meter testing records, fees for meter testing upon request, and meter reading, as required by rules 4303, 4304, 4305, 4306, and 4309;
- (G) information regarding benefit of service transfer policies as required by paragraph 4401(c);
- (H) information regarding installment payment plans and other plans, as required by rule 4404;
- (I) information regarding collection fees or miscellaneous service charges, as required by subparagraph 4404(c)(VI) and (c)(VIII).
- (J) information regarding any after-hour restoration fees, as required by paragraph 4409(b); and
- (K) all other rules, regulations, and policies covering the relations between the customer and the utility.

**4109. New or Changed Tariffs.**

- (a) A utility shall file with the Commission any new or changed tariffs. No new or changed tariff shall be effective unless it is filed with the Commission and either is allowed to go into effect by operation of law or is approved by the Commission.
- (b) A utility shall use one of the following processes to seek to add a new tariff or to change an existing tariff:
  - (I) The utility may file the proposed tariff, including the proposed effective date, accompanied by an advice letter pursuant to rule 1210. The utility shall provide notice in accordance with rule 1206. If the Commission does not suspend the proposed tariff in accordance with rule 1305 prior to the tariff's proposed effective date, the proposed tariff shall take effect on the proposed effective date.
  - (II) The utility may file an application to implement a proposed tariff on less than 30-days' notice, accompanied by the proposed tariff, including the proposed effective date. The utility shall provide notice in accordance with rule 1207. The application shall include the information required in paragraphs 4002(b) and 4002(c); shall explain the details of the proposed tariff, including financial data if applicable; shall state the facts which are the basis for the request that the proposed tariff become effective on less than 30-days' notice; and shall identify any prior Commission action, in any proceeding, pertaining to the present or proposed tariff.

- (III) Unless the Commission orders otherwise, a utility shall be permitted to file new tariffs complying with an order of the Commission or updating adjustment clauses previously approved by the Commission on not less than two business days' notice. No additional notice beyond the tariff filing itself shall be required.

**4110. Advice Letters.**

- (a) All advice letter filings shall comply with rule 1210 of the Commission's Rules of Practice and Procedure.
- (b) In addition to the requirements and contents in rule 1210, the advice letter shall include the estimated amounts, if any, by which the utility's revenues will be affected, calculated on an annual basis.
- (c) Customer notice of advice letter. If the utility is required by statute, Commission rule or order to provide notice to its customers of the advice letter, such notice shall include the requirements of subparagraphs 4002(d)(I) – (XII).

**4111. – 4199. [Reserved]**

**FACILITIES**

**4200. Construction, Installation, Maintenance, and Operation.**

The gas plant, equipment, and facilities of a utility shall be constructed, installed, inspected, maintained, and operated in accordance with accepted engineering and gas industry practices to assure continuity of service, uniformity in the quality of service, and the safety of persons and property.

**4201. Instrumentation.**

A utility purchasing natural gas energy or receiving natural gas energy for transportation services shall install, or shall require the interconnecting pipeline to provide, such instruments or meters as may be necessary to furnish information detailing the quantity and quality of gas received into its system as necessary to maintain measurement accuracy and acceptable gas quality.

**4202. Heating Value, Purity, and Pressure.**

- (a) A utility shall establish and maintain in its tariffs a minimum heating value for its gas, expressed in British Thermal Units per standard cubic foot. The minimum heating value shall be no less than the monthly average gross heating value of gas supplied by the utility in any given service area. No deviation below this minimum shall be permitted. The utility shall determine the heating value of gas by testing gas taken from such points on the utility's system and at such test frequencies as are reasonably necessary for a proper determination. The utility shall maintain records of tests conducted to determine the heating value of gas. The results of these tests shall be stated in terms of standard conditions.
- (b) A change in minimum heating value shall require an appropriate adjustment, if any, to rates.

- (c) The utility shall insure that the gas it supplies, if from multiple sources or if the supply from a single source changes in composition, is interchangeable for safe and efficient use. The utility shall insure that gas from new supply sources or from supply sources which the gas composition has changed is interchangeable with the gas it currently supplies. The utility shall evaluate interchangeability by means of one of the following:
  - (I) use of test results which establish that the gas supplied to the end-user falls within an acceptable range and which take into account the heating value, specific gravity, and composition of the gas;
  - (II) use of actual appliances to determine acceptability; or
  - (III) use of a standard in the natural gas industry.
- (d) A utility shall promptly readjust its customers' appliances and devices as necessary to render proper service if the readjustment is required for safe and efficient use in accordance with paragraph (c) of this rule. Unless otherwise ordered by the Commission, a readjustment made pursuant to this paragraph shall be done at no charge to the customer. If a utility determines that a readjustment pursuant to this paragraph is necessary, the utility shall notify the Commission, in writing, of the readjustment and of the reason for the readjustment.
- (e) A utility whose gas delivery exceeds 20 million cubic feet per annum shall test the heating value of gas at least once each week, unless the utility purchases or receives gas on a heat value basis or unless the interconnecting pipeline provides the utility with a record of the heating value of the gas delivered and the interconnecting pipeline's tests are made at least once each week.
- (f) All gas supplied to customers shall be substantially free of impurities which may cause corrosion of facilities or which may form corrosive or harmful fumes when burned in a properly-designed and properly-adjusted burner.
- (g) A LDC shall deliver gas at a pressure of six inches water column, plus or minus two inches water column, measured at the meter outlet, unless operating conditions require a higher delivery pressure. If a higher pressure is required, the utility shall require the customer to install appropriate pressure regulating equipment in the customer's lines, if necessary.
- (h) A utility shall monitor distribution pressure as follows:
  - (I) In a distribution system serving 100 or fewer customers, the utility shall semi-annually check distribution pressures by indicating gauges at the district regulator station or other appropriate point in the distribution system.
  - (II) In distribution system serving more than 100 and fewer than 500 customers, the utility shall provide at least one recording pressure gauge or telemetering pressure device at the pressure regulating station or at some other appropriate point in the distribution system.

(III) In a distribution system serving 500 or more customers, the utility shall maintain one or more additional recording pressure gauges or telemetering pressure devices and shall make frequent 24-hour records of the gas pressure prevailing at appropriate points in the system.

(i) In its tariff, a utility shall include a description of test methods, equipment, and frequency of testing used to determine the quality and pressure of gas service furnished.

**4203. Interruptions and Curtailments of Service.**

(a) A utility shall keep a record of all interruptions and curtailments of service on its entire system or on major divisions of its system, including a statement of the time, duration, and cause of each interruption or curtailment. A utility shall also keep a record of the time of starting up or shutting down of the compressing equipment and the period of operation of all regulators used for the maintenance of constant gas pressure.

(b) In its tariff a utility shall establish specific terms and conditions for interruptions and curtailments of service. The utility shall establish, and adhere to, interruption and curtailment priorities for sales service and for transportation service by customer class. These priorities shall be consistent with the requirements of this rule.

(c) A utility shall interrupt service within each class on an equitable basis, consistent with system constraints and its tariff. A utility shall interrupt service within a locale on a fair and reasonable basis, consistent with local conditions.

(d) A utility shall not make up any shortage by using the transportation customer's supplies without the transportation customer's consent.

(e) A utility shall curtail standby supply service to transportation customers who have contracted for standby supply service in accordance with the same system of class-by-class priorities as is applicable to sales customers established by the utility's tariffs.

(f) A utility may provide, under applicable sales tariffs, available supply service to gas transportation customers who have not purchased standby supply service from the utility and are experiencing supply shortages.

**4204. [Reserved].**

**4205. Gas Transportation Service Requirements.**

(a) In its tariffs, a utility shall establish maximum rates for gas transportation service. In addition, a utility which desires price flexibility shall include its minimum rates in its tariffs. The following apply to transportation tariff rates:

(I) Maximum rates for transportation shall be based on fully allocated cost methods and shall include an allowance for return on allocated rate base equal to the last rate of return authorized by the Commission for the utility.

- (II) A utility may, at its discretion, offer natural gas transportation standby capacity service or standby supply service. A utility may require separate charges for:
  - (A) natural gas transportation standby capacity (if offered);
  - (B) standby supply (if offered);
  - (C) administration, services and facilities; and
  - (D) a utility's avoidable purchased gas commodity costs based on current market-driven gas prices.
  
- (b) In its tariffs, a utility shall establish terms and conditions for gas transportation service, including at least the following:
  - (I) all criteria for determining gas transportation capacity;
  - (II) all gas transportation costs;
  - (III) all nomination requirements;
  - (IV) all measurement and facility requirements;
  - (V) as applicable, all gas supply cost provisions;
  - (VI) all gas balancing provisions;
  - (VII) all quality of gas requirements;
  - (VIII) the utility's line extension policy;
  - (IX) the gas transportation request form required by paragraph 4206(a);
  - (X) the utility's gas transportation standard gas transportation service agreement, which shall include the statements required by paragraph 4206(d); and
  - (XI) the utility's standard agency agreement required by paragraph 4206(e).

**4206. Gas Transportation Agreements.**

- (a) When a customer requests transportation service, a utility shall provide the customer requesting transportation with the utility's gas transportation form. This form shall set out clearly the information necessary for the utility to determine whether it can provide the requested transportation.
  
- (b) In determining whether capacity is available to provide the requested transportation, a utility shall take into account all conventional methods of delivering gas through its system, including without limitation forward haul, compression, exchange, flow reversal, backhaul, and displacement. The

utility is not required to perform exchanges or displacements over segments of its system which are not physically connected.

- (c) A utility shall process, shall approve or reject, and shall provide notification of its decision with respect to a transportation request within 60 days after receiving a written request from a transportation customer. If the utility rejects the request, the utility shall provide, within three business days, written notice of its decision to the customer and shall retain a record of the rejection notice for two years. The notice shall detail the reasons for the rejection and shall explain what changes are necessary to make the request acceptable. If the request is approved, the utility shall provide, within three business days, written notification of approval to the customer.
- (d) A utility shall maintain on file with the Commission a standard gas transportation agreement. All gas transportation agreements shall contain the following provisions.
  - (I) This agreement, and all its rates, terms and conditions as set out in this agreement and as set out in the tariff provisions which are incorporated into this agreement by reference, shall at all times be subject to modification by order of the Commission upon notice and hearing and a finding of good cause therefore. In the event that any party to this agreement requests the Commission to take any action which could cause a modification in the conditions of this agreement, the party shall provide written notice to the other parties at the time of filing the request with the Commission.
  - (II) If the end-use customer uses a marketing broker for nomination, gas purchases, and balancing, the end-use customer shall provide the utility with an agency agreement.
- (e) A utility shall maintain on file with the Commission the standard agency agreement to be used when an end-use transportation customer uses a third party for any services related to nomination, gas purchases, and balancing activities.
- (f) A utility shall maintain logs showing all requests for gas transportation. The log shall contain the following information: the identity of the party making the transportation request, the date of the request, the volume requirements, duration, receipt and delivery points, type of service, and the disposition of the request. The utility shall retain these logs for two years.

**4207. Purchases Replaced by Transportation.**

- (a) Any reduction of gas purchases by a current sales customer who replaces sales purchases with transportation directly reduces a utility's obligation to provide gas to that customer on both a peak day and on an annual volume basis. If offered by the utility, a customer may retain rights to gas supplies by electing to pay for standby capacity service and standby supply service.
- (b) Any reduction of gas purchases by a current interruptible sales customer who replaces said purchases with transportation gas directly reduces the utility's obligation to provide gas supplies to that customer on an annual volume basis. At the discretion of the utility, a customer may retain rights to interruptible gas supplies by electing to pay for standby supply service.

- (c) If a sales customer converts all, or a portion, of its service to transportation and if it does not elect standby supply service, then the customer must reapply for sales service in the future if it wishes to convert the transportation portion of its service back to sales service.
- (d) The utility shall have no sales service obligation to a transportation customer who is solely responsible for procuring its own gas supply. The customer may retain rights to gas supplies by electing to pay for standby supply service.

**4208. Anticompetitive Conduct Prohibited.**

- (a) A utility shall apply all transportation rates and policies without undue discrimination or preference to its affiliates. Each contract to transport gas for a marketing or brokering affiliate of a utility shall be an arm's-length agreement containing only terms which are available to other transportation customers.
- (b) A utility is prohibited from engaging in anticompetitive conduct, discriminatory behavior, and preferential treatment in transporting gas, including (without limitation) the following:
  - (I) disclosure to a marketing or brokering affiliate of confidential information provided by nonaffiliated transportation customers;
  - (II) disclosing to any transportation customer the utility's own confidential information unless the same information is communicated contemporaneously to all current transportation customers;
  - (III) disclosing to any transportation customer of information filed with a transportation request unless the same information is communicated contemporaneously to all current transportation customers;
  - (IV) providing any false or misleading information, or failing to provide information, regarding the availability of capacity for transportation service;
  - (V) tying an agreement to release gas to an agreement by the transportation customer to obtain services from a marketing or brokering affiliate of the utility or to an offer by the utility to provide or to expedite transportation service to its affiliate for the released gas;
  - (VI) providing any false or misleading information, or failing to provide information, about gas releases;
  - (VII) failing to notify all affiliate brokers and marketers and all transportation customers of gas releases at the same time and in the same manner or otherwise allowing marketing or brokering affiliates preferential access to released gas;
  - (VIII) lending gas to a marketing or brokering affiliate to meet balancing requirements except under terms available to other transportation customers;
  - (IX) directing potential customers to the utility's own marketing or brokering affiliate, but the utility may provide a list of all registered gas marketers and brokers, including its affiliates;



- (X) charging lower rates to a transportation customer conditioned on the purchase of gas from the utility's marketing or brokering affiliate;
- (XI) conditioning the availability of transportation service upon the use of the utility's marketing or brokering affiliate;
- (XII) providing exchange or displacement services to one transportation customer without providing them to others on the same terms and conditions;
- (XIII) giving its marketing affiliate preference over nonaffiliated customers in matters relating to transportation including, but not limited to, scheduling, balancing, transportation, storage, or curtailment priority;
- (XIV) disclosing to its affiliate any information the utility received from a nonaffiliated transportation customer or potential nonaffiliated transportation customer;
- (XV) failing contemporaneously to provide identical gas transportation sales or marketing information it provides to a marketing affiliate to all potential transportation customers, affiliated and nonaffiliated, on its system; and
- (XVI) failing to make available to all similarly-situated nonaffiliated transportation customers discounts which are comparable to those made to an affiliated marketer.

**4209. [Reserved].**

**4210. Line Extension.**

- (a) A utility shall have tariffs which set out its line extension policies, procedures, and conditions.
- (b) In its tariff a LDC shall include the following provisions for gas main extensions and service lateral extensions from its distribution system:
  - (I) the terms and conditions, by customer class, under which an extension will be made;
  - (II) provisions requiring the utility to provide to a customer or to a potential customer, upon request, service lateral connection information necessary to allow the customer's or potential customer's facilities to be connected to the utility's system;
  - (III) provisions requiring the utility to exercise due diligence in providing the customer or potential customer with an estimate of the anticipated cost of a connection or extension; and
  - (IV) provisions addressing steps to ameliorate the rate and service impact upon existing customers, including stating in the tariff the procedures by which future customers would share costs incurred by the initial or existing customers served by a connection or extension (as, for example, by including the procedures by which a refund of customer connection or extension payments would be made when appropriate).

**4211. – 4299. [Reserved].**

## **METERS**

### **4300. Service Meters and Related Equipment.**

- (a) All meters used in connection with gas metered service for billing purposes shall be furnished, installed, and maintained by the utility.
- (b) All equipment, devices, or facilities (including, without limitation, service meters) furnished by the utility and which the utility maintains and renews shall remain the property of the utility and may be removed by it at any time after discontinuance of service.
- (c) Each service meter shall indicate clearly the cubic feet or other units of service for which the customer is charged for service through each meter. In cases in which the dial reading of a meter, other than an orifice or other chart type meter, must be multiplied by a constant or factor to obtain the units consumed, the factor, factors, or constant shall be clearly marked on the dial or face of the meter, if possible. In the alternative, the constant, constants, or factor, or the method of calculating the constant, constants, or factor, shall be stated clearly on a customer's bill, with step by step instructions to allow customer to convert the unit of measurement from the dial of the meter to the billing unit or billing determinant on the bill.

### **4301. Location of Service Meters.**

- (a) As of the time of installation, meters shall be located in accordance with the pertinent utility tariffs and in accordance with accepted safe practice and gas utility industry standards.
- (b) As of the time of installation, meters shall be located so as to be easily accessible for reading, testing, and servicing in accordance with accepted safe practice and in accordance with gas utility industry standards.

### **4302. Service Meter Accuracy.**

- (a) Before being installed for use by a customer, every gas service meter, whether new, repaired, or removed from service for any cause shall be in good order and, except as provided in paragraph (b) of this rule, shall be adjusted to be correct to within one percent when passing gas at 20 percent of its rated capacity at one-half inch water column differential.
- (b) New rotary displacement type gas service meters in sizes having a rated capacity of more than 5,000 cubic feet per hour at a differential not to exceed two inches water column shall be tested and calibrated at the factory in accordance with recognized and accepted practices. These meters shall also be adjusted to be correct within two percent slow and one percent fast when passing gas at ten percent of its rated capacity and shall be adjusted to be correct within one percent slow and one percent fast when passing gas at 100 percent of its rated capacity. Prior to reuse of a rotary displacement type meter that has been removed from service, the meter shall pass the same testing criteria as a new meter.

### **4303. Meter Testing Equipment and Facilities.**

- (a) A utility shall provide, or shall arrange for a qualified third party to provide, such equipment and facilities as may be necessary to make the tests and to provide the service required. Such

equipment and facilities shall be available at all reasonable times for inspection by Commission staff.

- (b) A utility having more than 200 meters in service shall maintain, or shall require the qualified third party that provides meter testing equipment and facilities to maintain, suitable gas meter testing equipment in proper adjustment so as to register the condition of meters tested within one-half of one percent. The utility shall have and shall maintain, for the testing equipment, necessary certificate(s) of calibration showing that the equipment has been tested with a standard certified by the National Institute of Standards and Technology or other laboratory of recognized standing.
- (c) In its tariff, a utility shall include a description of its meter testing equipment and of the methods employed to ascertain and to maintain accuracy of all testing equipment.
- (d) A utility shall keep records of certification and calibrations for all testing equipment required by this rule for the life of the equipment.

**4304. Scheduled Meter Testing.**

- (a) A utility shall test, or shall arrange for testing of, service meters in accordance with the schedule in this rule or in accordance with a sampling program approved by the Commission.
- (b) If it wishes to use a sampling program, a utility shall file an application to request approval of a sampling program. The application shall include:
  - (I) the information required by paragraphs 4002(b) and 4002(c);
  - (II) a description of the sampling program which the utility wishes to use. This description shall include, at a minimum the following:
    - (A) the type(s) of meters subject to the sampling plan;
    - (B) the frequency of testing;
    - (C) the procedures to be used for the sampling;
    - (D) the meter test method to be used;
    - (E) the accuracy of the testing and of the sampling plan;
    - (F) an explanation of the reason(s) for the requested sampling program; and
    - (G) an analysis which demonstrates that, with respect to assuring the accuracy of the service meters tested, the requested sampling program is at least as effective as the schedule in this rule.
- (c) Revisions to any portion of a sampling program approved pursuant to the procedure in paragraph (b) of this rule shall be accomplished by the filing of, and Commission approval of, a new application.

- (d) Every service meter shall be tested and adjusted before installation to ensure that it registers accurately and conforms with the requirements of rule 4302. In addition, every service meter shall be tested on a periodic basis, as follows:
  - (I) diaphragm type gas service meter in sizes having rated capacity of 800 cubic feet or less per hour at one-half inch water column differential, every six years;
  - (II) diaphragm type gas service meter in sizes having a rated capacity of more than 800 cubic feet per hour at one-half inch water column differential, every five years;
  - (III) rotary displacement type gas service meter in sizes having a rated capacity of 5,000 cubic feet or less per hour at one-half inch water column differential, every five years;
  - (IV) rotary displacement type gas service meters in sizes having a rated capacity of more than 5,000 cubic feet per hour at a differential not to exceed two inches water column, the frequency of testing stated in the utility's tariff;
  - (V) orifice meters, not less than once each year; and
  - (VI) meter types not listed, not less than once each year.
- (e) In its tariff, a utility shall describe the utility's practices concerning the following:
  - (I) testing and adjustment of service meters at installation; and
  - (II) periodic testing after installation.

**4305. Meter Testing Upon Request.**

- (a) If a customer disputes the accuracy of a meter or disputes the billing that implicates the accuracy of a meter, the utility furnishing metered gas service shall inform the customer of their rights to have the meter tested as specified in this rule. Within 30 days of a customer's request, the utility shall test the meter's accuracy using standardized testing equipment. The test shall be conducted free of charge if the meter has not been tested within the previous 12 months; otherwise the utility may charge a fee for performing the test. The utility shall provide a written report of the test results to the customer and shall maintain the report on file for at least two years from the date of the test. If, upon completion of the test, the disputed meter is found to be inaccurate beyond the limits prescribed in rule 4302, it shall be deemed out of compliance.
- (b) Should a customer request and receive a meter test as prescribed in paragraph 4305(a) and continue to dispute the accuracy of the meter, or the billing that implicates the accuracy of the meter, the utility shall give notice to the customer of his or her right to request independent testing of the meter. The customer's right to request independent testing of the meter shall expire on the 30<sup>th</sup> day after the date of the utility's notice. Upon the customer's request, the utility shall make the disputed meter available for independent testing by a qualified meter testing facility of the customer's choosing. The customer is not entitled to take physical possession of the disputed meter. To be a qualified meter testing facility, the testing facility must be capable of testing the meter to meet all meter standards and requirements required by these rules.

- (c) If, upon completion of an independent test as prescribed in paragraph 4305(b), the disputed meter is found to be accurate within the limits of rule 4302, the customer shall bear all costs associated with conducting the independent test. If, upon completion of an independent test as prescribed in paragraph 4305(b), the disputed meter is found to be inaccurate beyond the limits prescribed in rule 4302, the meter shall be deemed out of compliance and the utility shall bear all costs associated with conducting the independent test.
- (d) In its tariff, a utility shall include any fees associated with customer-requested meter testing conducted within 12 months of a prior test.
- (e) If a meter is deemed out of compliance under this rule, the utility shall either inform the customer of his or her right to request a refund pursuant to rule 4402 or unilaterally issue the refund.

**4306. Records of Tests and Meters.**

- (a) For each meter owned or installed, a utility shall maintain a record showing the date of purchase, the manufacturer's serial number, the record of the present or previously installed location, and the date and results of the last test performed by the utility. This record shall be retained for the life of the meter plus 30 months.
- (b) Whenever a meter is tested either on request or upon complaint, the test record shall include the information necessary for identifying the meter, the reason for making the test, the reading of the meter if removed from service, the result of the test, and all data taken at the time of the test in a sufficiently complete form to permit the convenient checking of the methods employed and the calculations made. This record shall be retained for at least two years.

**4307- 4308. [Reserved].**

**4309. Meter Reading.**

- (a) Upon a customer's request, a utility shall provide written documentation showing the date of the most recent reading of the customer's meter and the total usage expressed in cubic feet or other unit of service recorded. On request, a utility supplying metered service shall explain to a customer in a clear non-technical statement its method of reading the customer's meter.
- (b) A utility shall include in its tariff a clear statement describing when meters will be read by the utility and the circumstances, if any, under which the customer must read the meter and submit the data to the utility. This statement shall specify in detail the procedure that the customer must follow and shall specify all special conditions that apply to each class of service.
- (c) Absent good cause, a utility shall read a meter monthly. For good cause shown, a utility shall read a meter at least once every six months.

**4310. – 4399. [Reserved]**

## **BILLING AND SERVICE**

### **4400. Applicability.**

Rules 4400 through 4412 apply to residential customers, small commercial customers and agricultural customers served pursuant to a LDC's rates or tariffs. Rules 4400 through 4405 and rules 4407 through 4412 shall not apply to customers served under a LDC's transportation rates or tariffs. In its tariffs, a LDC shall define "residential," "small commercial" and "agricultural" customers to which these rules apply. The LDC may elect to apply the same or different terms and conditions of service to other customers.

### **4401. Billing Information and Procedures.**

- (a) All bills issued to customers for metered service furnished shall show:
- (I) the dates and meter readings beginning and ending the period during which service was rendered;
  - (II) an appropriate rate or rate code identification for each separate rate component charged to the bill. Each component shall be designated on the bill in a manner such that the rate or charge can be identified clearly when referencing approved rates found in the utility's tariff;
  - (III) the net amount due for regulated charges;
  - (IV) the date by which payment is due, which shall not be earlier than 15 days after the mailing or the hand-delivery of the bill;
  - (V) a distinct marking to identify an estimated bill;
  - (VI) the total amount of all payments or other credits made to the customer's account during the billing period;
  - (VII) any past due amount. Unless otherwise stated in a tariff or Commission rule, an account becomes "past due" on the 31st day following the due date of current charges;
  - (VIII) the identification of, and amount due for, unregulated charges, if applicable;
  - (IX) any transferred amount or balance from any account other than the customer's current account; and
  - (X) all other essential facts upon which the bill is based, including factors and constants, as applicable.
- (b) A utility that bills for unregulated services or goods shall allocate partial payments first to regulated charges and then to unregulated charges or non-tariff charges and to the oldest balance due separately within each category.

- (c) A utility that transfers to a customer a balance from the account of a person other than that customer shall have in its tariffs the utility's benefit of service transfer policies and criteria. The tariffs shall contain an explanation of the process by which the utility will verify, prior to billing a customer under the benefit of service tariff, that the person to be billed in fact received the benefit of service.
- (d) A utility may transfer a prior unpaid debt to a customer's bill if the prior bill was in the name of the customer and the utility has informed the customer of the transferred amount and of the source of the unpaid debt (for example, and without limitation, the address of the premises to which service was provided and the period during which service was provided).
- (e) If it is offered in a tariff, upon request from a customer and where it is technically feasible, a utility may have the option to provide electronic billing (e-billing), in lieu of a printed bill, to the requesting customer. If a utility offers the option of e-billing, the following shall apply:
  - (I) the utility shall obtain the affirmative consent of a customer to accept such a method of billing in lieu of printed bills;
  - (II) the utility shall not charge a fee for billing through the e-billing option;
  - (III) the utility shall not charge a fee based on customer payment options that is different from the fee charged for the use of the same customer payment options by customers who receive printed bills; and
  - (IV) a bill issued electronically shall contain the same disclosures and Commission-required information as those contained in the printed bill provided to other customers.

**4402. Adjustments for Meter and Billing Errors.**

- (a) A utility shall adjust a customer's bill(s) for gas incorrectly metered or billed as follows.
  - (I) When, upon any meter accuracy test, a meter is found to be running slow in excess of error tolerance levels allowed under rule 4302, the utility may charge for one-half of the under-billed amount for the period dating from the discovery of the meter error back to the previous meter test, with such period not to exceed six months.
  - (II) When, upon any meter accuracy test, a meter is found to be running fast in excess of error tolerance levels allowed under rule 4302, the utility shall refund one-half of the excess charge for the period dating from the discovery of the meter error back to the previous meter test, with such period not to exceed two years.
  - (III) When a meter does not register, registers intermittently, or partially registers for any period, the utility may estimate, using the method stated in its tariff, a charge for the gas used based on amounts metered to the customer over a similar period in previous years. The period for which the utility charges the estimated amount shall not exceed six months.

- (IV) In the event of under-billings not provided for in subparagraph (a)(I) or (III) of this rule (such as, but not limited to, an incorrect multiplier, an incorrect register, or a billing error), the utility may charge for the period during which the under-billing occurred, with such period not to exceed six months.
- (V) In the event of over-billings not provided for in subparagraph (a)(II) of this rule, the utility shall refund for the period during which the over-billing occurred, with such period not to exceed two years.
- (b) The periods set out in paragraph (a) of this rule shall commence on the earliest date on which either the customer notifies the utility or the utility notifies the customer of a meter or billing error, the customer informs the utility of a billing or metering error, or a dispute based on a billing or metering error, or the customer submits an informal complaint to the Consumer Assistance Unit of the Commission. <http://www.colorado.gov/pacific/dora/file-consumer-complaint>.
- (c) In the event of an over-billing, the customer may elect to receive the refund as a credit to future billings or as a one-time payment. If the customer elects a one-time payment, the utility shall make the refund within 30 days. Such over-billings shall not be subject to interest.
- (d) In the event of under-billing, the customer shall be eligible and may elect to enter into a payment arrangement on the under-billed amount. The payment arrangement shall be equal in length to the length of time during which the under-billing occurred. Such under-billings shall not be subject to interest.

**4403. Applications for Service, Customer Deposits, and Third-Party Guarantee Arrangements.**

- (a) A utility shall process an application for utility service which is made either orally or in writing and shall apply nondiscriminatory criteria with respect to the requirement of a deposit prior to commencement of service.
- (b) If billing records are available for a customer who has received past service from the utility, the utility shall not require that person to make new or additional deposits to guarantee payment of current bills unless the records indicate recent or substantial delinquencies. All customers shall be treated without undue discrimination with respect to deposit requirements, and such requirements shall be specifically stated in to the utility's tariff.
- (c) A utility shall not require a deposit from an applicant for service who provides written documentation of a 12 consecutive month good credit history from the utility from which that person received similar service. For purposes of this paragraph, the 12 consecutive months must have ended no earlier than 60 days prior to the date of the application for service.
- (d) If a utility uses credit scoring to determine whether to require a deposit from an applicant for service or a customer, the utility shall have a tariff which describes, for each scoring model that it uses, the credit scoring evaluation criteria and the credit score limit which triggers a deposit requirement.
- (e) All utilities requiring deposits shall offer customers at least one non-cash alternative that does not require the use of the customer's social security number, in lieu of a cash deposit.



- (f) If a utility uses credit scoring, prior payment history with the utility, or customer-provided prior payment history with a like utility as a criterion for establishing the need for a deposit, the utility shall include in its tariff the specific evaluation criteria which trigger the need for a deposit.
- (g) If a utility denies an application for service or requires a deposit as a condition of providing service, the utility immediately shall inform the applicant for service of the decision and shall provide, within three business days, a written explanation to the applicant for service stating the specific reasons the application for service has been denied or a deposit is required.
- (h) No utility shall require any surety other than either a deposit to secure payment for utility services or a third-party guarantee of payment in lieu of a deposit. In no event shall the furnishing of utility services or extension of utility facilities, or any indebtedness in connection therewith, result in a lien, mortgage, or other interest in any real or personal property of the customer unless such indebtedness has been reduced to a judgment. Should the guarantor terminate service or terminate the third party guarantee before the customer has established a satisfactory payment record for 12 consecutive months, the utility, applying the criteria contained in its tariffs, may require a deposit or a new third party guarantor.
- (i) A deposit shall not exceed an amount equal to an estimated 90 days' bill of the customer, except in the case of a customer whose bills are payable in advance of service, in which case the deposit shall not exceed an estimated 60 days' bill of the customer. The deposit may be in addition to any advance, contribution in aid of construction or guarantee required by the utility tariff in connection with construction of lines or facilities, as provided in the extension policy in the utility's tariffs.
- (j) A utility receiving deposits shall maintain records showing:
  - (I) the name of each customer making a deposit;
  - (II) the amount and date of the deposit;
  - (III) each transaction, such as the payment of interest or interest credited, concerning the deposit;
  - (IV) each premise where the customer receives service from the utility while the deposit is retained by the utility;
  - (V) if the deposit was returned to the customer, the date on which the deposit was returned to the customer; and
  - (VI) if the unclaimed deposit was paid to the energy assistance organization, the date on which the deposit was paid to the energy assistance organization.
- (k) In its tariff, a utility shall clearly state its customer deposit policy for establishing or maintaining service. The tariff shall state the circumstances under which a deposit will be required and the circumstances under which it will be returned.

- (l) A utility shall issue a receipt to every customer from whom a deposit is received. No utility shall refuse to return a deposit or any balance to which a customer may be entitled solely on the basis that the customer is unable to produce a receipt.
- (m) The payment of a deposit shall not relieve any customer from the obligation to pay current bills as they become due. A utility is not required to apply any deposit to any indebtedness of the customer to the utility, except for utility services due or past due after service is terminated.
- (n) A utility shall pay simple interest on a deposit at the percentage rate per annum as calculated by the Commission staff and in the manner provided in this paragraph.
  - (I) At the request of the customer, the interest shall be paid to the customer either on the return of the deposit or annually. The simple interest on a deposit shall be earned from the date the deposit is received by the utility to the date the customer is paid. At the option of the utility, interest payments may be paid directly to the customer or credited to the customer's account.
  - (II) The simple interest to be paid on a deposit during any calendar year shall be at a rate equal to the average for the period October 1 through September 30 (of the immediately preceding year) of the 12 monthly average rates of interest expressed in percent per annum, as quoted for one-year United States Treasury constant maturities, as published in the Federal Reserve Bulletin, by the Board of Governors of the Federal Reserve System. Each year, the Commission staff shall compute the interest rate to be paid. If the difference between the existing customer deposit interest rate and the newly calculated customer deposit interest rate is less than 25 basis points, the existing customer deposit interest rate shall continue for the next calendar year. If the difference between the existing customer deposit interest rate and the newly calculated customer deposit interest rate is 25 basis points or more, the newly calculated customer deposit interest rate shall be used. The Commission shall send a letter to each utility stating the rate of interest to be paid on deposits during the next calendar year. Annually following receipt of Commission staff's letter, if necessary, a utility shall file by advice letter or application, as appropriate, a revised tariff, effective the first day of January of the following year, or on an alternative date set by the Commission, containing the new rate of interest to be paid upon customers' deposits, except when there is no change in the rate of interest to be paid on such deposits.
- (o) A utility shall have tariffs concerning third-party guarantee arrangements and, pursuant to those tariffs, shall offer the option of a third party guarantee arrangement for use in lieu of a deposit. The following shall apply to third-party guarantee arrangements:
  - (I) an applicant for service or a customer may elect to use a third-party guarantor in lieu of paying a deposit;
  - (II) the third-party guarantee form, signed by both the third-party guarantor and the applicant for service or the customer, shall be provided to the utility;
  - (III) the utility may refuse to accept a third-party guarantee if the guarantor is not a customer in good standing at the time of the presentation of the guarantee to the utility;

- (IV) the amount guaranteed shall not exceed the amount which the applicant for service or the customer would have been required to provide as a deposit;
  - (V) the guarantee shall remain in effect until the earlier of the following occurs:
    - (A) the guarantee is terminated in writing by the guarantor;
    - (B) if the guarantor was a customer at the time of undertaking the guarantee, the guarantor ceases to be a customer of the utility; or
    - (C) the customer has established a satisfactory payment record, as defined in the utility's tariffs, for 12 consecutive months.
  - (VI) Should the guarantor terminate service or terminate the third party guarantee before the customer has established a satisfactory payment record for 12 consecutive months, the utility, applying the criteria contained in its tariffs, may require a deposit or a new third party guarantor.
- (p) A utility shall pay all unclaimed monies, as defined in § 40-8.5-103(5), C.R.S., that remain unclaimed for more than two years to the energy assistance organization. "Unclaimed monies" shall not include undistributed refunds for overcharges subject to other statutory provisions and rules and credits to existing customers from cost adjustment mechanisms.
- (I) Monies shall be deemed unclaimed and presumed abandoned when left with the utility for more than two years after termination of the services for which the deposit or the construction advance was made or when left with the utility for more than two years after the deposit or the construction advance becomes payable to the customer pursuant to a final Commission order establishing the terms and conditions for the return of such deposit or advance and the utility has made reasonable efforts to locate the customer.
  - (II) Interest on a deposit shall accrue at the rate established pursuant to paragraph (n) of this rule commencing on the date on which the utility receives the deposit and ending on the date on which the deposit is paid to the energy assistance organization. If the utility does not pay the unclaimed deposit to the energy assistance organization within four months of the date on which the unclaimed deposit is deemed to be unclaimed or abandoned pursuant to subparagraph (p)(I) of this rule, then at the conclusion of the four-month period, interest shall accrue on the unclaimed deposit at the rate established pursuant to paragraph (n) of this rule plus six percent.
  - (III) If payable under the utility's line extension tariff provisions, interest on a construction advance shall accrue at the rate established pursuant to paragraph (n) of this rule commencing on the date on which the construction advance is deemed to be owed to the customer pursuant to the utility's extension policy and ending on the date on which the construction advance is paid to the energy assistance organization. If the utility does not pay the unclaimed construction advance to the energy assistance organization within four months of the date on which the unclaimed construction advance is deemed to be unclaimed or abandoned pursuant to subparagraph (p)(I) of this rule, then at the conclusion of the four-month period, interest shall accrue on the unclaimed construction advance at the rate established pursuant to paragraph (n) of this rule plus six percent.

- (q) A utility shall resolve all inquiries regarding a customer's unclaimed monies and shall not refer such inquiries to the energy assistance organization.
- (r) If a utility has paid unclaimed monies to the energy assistance organization, a customer later makes an inquiry claiming those monies, and the utility resolves the inquiry by paying those monies to the customer, the utility may deduct the amount paid to the customer from future funds submitted to the energy assistance organization.

**4404. Installment Payments.**

- (a) A utility shall make a budget or level payment plan available for its customers and have such plan clearly defined in its tariff.
- (b) A utility shall have in its tariff an installment payment plan which permits a customer to make installment payments if one of the following applies.
  - (I) The plan is to pay regulated charges from past billing periods and the past due amount arises solely from events under the utility's control (such as, without limitation, meter malfunctions, billing errors, utility meter reading errors, or failures to read the meter, except where the customer refuses to read the meter and it is not readily accessible to the utility). A utility shall advise a customer who is eligible for this type of plan of the customer's eligibility. At the request of the customer and at the customer's discretion, an installment payment plan under this subparagraph shall extend over a period equal in length to that during which the errors were accumulated and shall not include interest.
  - (II) The customer pays at least ten percent of the amount shown on the notice of discontinuance for regulated charges and enters into an installment payment plan on or before the expiration date of the notice of discontinuance.
  - (III) The customer pays at least ten percent of any regulated charges amount more than 30 days past due and enters into an installment payment plan on or before the last day covered by a medical certification. A customer who has entered into and failed to abide by an installment payment plan prior to receiving a medical certification shall pay all amounts that were due for regulated charges up to the date on which the customer presented a medical certification which meets the requirements of subparagraph 4407(e)(IV) and then may resume the installment payment plan.
  - (IV) If service has been disconnected, the customer pays at least any collection and reconnection charges and enters into an installment payment plan. This subparagraph shall not apply if service was discontinued because the customer breached a prior payment arrangement.
- (c) Installment payment plans shall include the following amounts that are applicable at the time the customer requests a payment arrangement:
  - (I) the unpaid remainder of amounts due for regulated charges shown on the notice of discontinuance;

- (II) any amounts due for regulated charges not included in the amount shown on the notice of discontinuance which have since become more than 30 days past due;
  - (III) all current regulated charges contained in any bill which is past due but is less than 30 days past the due date;
  - (IV) any new regulated charges contained in any bill which has been issued but is not past due;
  - (V) any regulated charges which the customer has incurred since the issuance of the most recent monthly bill;
  - (VI) any collection fees as provided for in the utility's tariff, whether or not such fees have appeared on a regular monthly bill;
  - (VII) any deposit, whether already billed, billed in part, or required by the utility's tariff, due for discontinuance or delinquency or to establish initial credit, other than a deposit required as a condition of initiating service; and
  - (VIII) any other regulated charges or fees provided in the utility's tariff (including without limitation miscellaneous service charges, investigative charges, and checks returned for insufficient funds charges), whether or not they have appeared on a regular monthly bill.
- (d) Within seven calendar days of entering into a payment arrangement with a customer, a utility shall provide the customer with this rule and a statement describing the payment arrangement. The statement describing the payment arrangement shall include the following:
- (I) the terms of the payment plan; and
  - (II) a description of the steps which the utility will take if the customer does not abide by payment plan.
- (e) Except as provided in subparagraph (b)(l) of this rule, an installment payment plan shall consist, at a minimum, of equal monthly installments for a term selected by the customer but not to exceed six months. In the alternative, the customer may choose a modified budget billing, level payment, or similar tariff payment arrangement in which the total due shall be added to the preceding year's total billing to the customer's premises, modified for any base rate or cost adjustment changes. The resulting amount shall be divided and billed in 11 equal monthly budget billing payments, followed by a settlement billing in the twelfth month, or shall follow other payment-setting practices consistent with the tariff plan available.

- (f) For an installment payment plan entered into pursuant to this rule, the first monthly installment payment, and with the new charges (unless the new charges have been made part of the arrangement amount) shall be due on a date which is not earlier than the next regularly-scheduled due date of the customer who is entering into the installment payment plan. Succeeding installment payments, together with the new charges, shall be due in accordance with the due date established in the installment payment plan. Any payment not made on the due date established in the installment payment plan shall be considered in default. Any new charges that are not paid by the due date shall be considered past due, excluding those circumstances covered in subparagraph (b)(I) of this rule.
- (g) This rule shall not be construed to prevent a utility from offering any other installment payment plan terms to avoid discontinuance or terms for restoration of service, provided the terms are at least as favorable to the customer as the terms set out in this rule.

**4405. Service, Rate, and Usage Information.**

- (a) In addition to the requirement found in rule 1206, a utility shall inform its customers of any change proposed or made in any term or condition of its service if that change or proposed change will affect the quality of the service provided.
- (b) A utility shall transmit information provided pursuant to this rule through the use of a method (such as, without limitation, bill inserts or periodic direct mail) that will assure receipt by each customer.
- (c) Upon request, a utility shall provide the following information to a customer.
  - (I) A clear and concise explanation of the existing rate schedule applicable to the customer, the rate components for that rate schedule, and an explanation of how those components are calculated and applicable to the customer. This shall be provided within ten days of a customer's request or, in the case of a new customer, within 60 days of the commencement of service.
  - (II) A clear and concise statement of the customer's actual consumption or degree-day adjusted consumption of gas for each billing period during the prior year, unless such consumption data are not reasonably ascertainable by the utility.
  - (III) A clear and concise explanation of the terms and conditions of service applicable to the customer.

**4406. Itemized Billing Components.**

- (a) A utility shall provide itemized gas cost information to all customers commencing with the first complete billing cycle in which the new rates are in effect. The information may be provided in the form of a bill insert or a separate mailing.
- (b) The information provided pursuant to this rule shall include the following:
  - (I) the per-unit and fixed service rates to be billed to the customer;

- II) the per-unit and monthly gas commodity costs for that customer;
- (III) the per-unit and monthly costs of upstream services for that customer; and
- (IV) the monthly gas demand side management costs for that customer.

**4407. Discontinuance of Service.**

- (a) A utility shall not discontinue the service of a customer for any reason other than the following:
  - (I) nonpayment of regulated charges;
  - (II) fraud or subterfuge;
  - (III) service diversion;
  - (IV) equipment tampering;
  - (V) safety concerns;
  - (VI) discontinuance ordered by any appropriate governmental authority; or
  - (VII) properly discontinued service being restored by someone other than the utility when the original cause for proper discontinuance has not been cured.
- (b) A utility shall not discontinue service for nonpayment of any of the following:
  - (I) any amount which has not appeared on a regular monthly bill or which is not past due. Unless otherwise stated in a tariff or Commission rule, an account becomes "past due" on the 31st day following the due date of current charges;
  - (II) any amount due on another account now or previously held or guaranteed by the customer, or with respect to which the customer received service, unless the amount has first been transferred either to an account which is for the same class of service or to an account which the customer has agreed will secure the other account. Any amount so transferred shall be considered due on the regular due date of the bill on which it first appears and shall be subject to notice of discontinuance as if it had been billed for the first time;
  - (III) any amount due on an account on which the customer is or was neither the customer of record nor a guarantor, or any amount due from a previous occupant of the premises. This subparagraph does not apply if the customer is or was obtaining service through fraud or subterfuge or if paragraph 4401(c) applies;
  - (IV) any amount due on an account for which the present customer is or was the customer of record, if another person established the account through fraud or subterfuge and without the customer's knowledge or consent;

- (V) any delinquent amount, unless the utility can supply billing records from the time the delinquency occurred;
  - (VI) any debt except that incurred for service rendered by the utility in Colorado; or
  - (VII) any unregulated charge.
- (c) If the utility discovers any connection or device installed on the customer's premises, including any energy-consuming device in the proximity of the utility's meter, which would prevent the meter from registering the actual amount of energy used, the utility shall do one of the following.
- (I) Remove or correct such devices or connections. If the utility takes this action, it shall leave at the premises a written notice which advises the customer of the violation, of the steps taken by the utility to correct it, and of the utility's ability to bill the customer for any estimated energy consumption not properly registered. This notice shall be left at the time the removal or correction occurs.
  - (II) Provide the customer with written notice that the device or connection must be removed or corrected within 15 days and that the customer may be billed for any estimated energy consumption not properly registered. If the utility elects to take this action and the device or connection is not removed or corrected within the 15 days permitted, then within seven calendar days from the expiration of the 15 days, the utility shall remove or correct the device or connection pursuant to subparagraph (c)(I) of this rule.
- (d) If a utility discovers evidence that any utility-owned equipment has been tampered with or that service has been diverted, the utility shall provide the customer with written notice of the discovery. The written notice shall inform the customer of the steps the utility will take to determine whether non-registration of energy consumption has or will occur and shall inform the customer that the customer may be billed for any estimated energy consumption not properly registered. The utility shall mail or hand-deliver the written notice within three calendar days of making the discovery of tampering or service diversion.
- (e) A utility shall not discontinue service, other than to address safety concerns, if one of the following is met:
- (I) If a customer at any time tenders full payment in accordance with the terms and conditions of the notice of discontinuance to a utility employee authorized to receive payment. Payment of a charge for a service call shall not be required to avoid discontinuance.
  - (II) If a customer pays, on or before the expiration date of the notice of discontinuance, at least one-tenth of the amount shown on the notice and enters into an installment payment plan with the utility, as provided in rule 4404.
  - (III) If it is between 12 Noon on Friday and 8 a.m. the following Monday; between 12 Noon on the day prior to and 8:00 a.m. on the day following any state or federal holiday; or between 12 Noon on the day prior to and 8:00 a.m. on the day following any day during which the utility's local office is not open.



- (IV) Medical emergencies.
- (A) A utility shall postpone discontinuance of gas service to a residential customer for 60 days from the date of a medical certificate issued by a Colorado-licensed physician or health care practitioner acting under a physician's authority which evidences that discontinuance of service will aggravate an existing medical emergency or create a medical emergency for the customer or a permanent resident of the customer's household. The customer may receive a single 30-day extension by providing a second medical certification prior to the expiration of the original 60-day period. A customer may invoke this subparagraph 4407(e)(IV)(A) only once in any twelve consecutive months.
  - (B) As a condition of obtaining a new installment payment plan on or before the last day covered by a medical certificate, a customer who had already entered into a payment arrangement, but had broken the arrangement prior to seeking a medical certification, may be required to pay all amounts that were due up to the date of the original medical certificate as a condition of obtaining a new payment arrangement. At no time shall a payment from the customer be required as a condition of honoring a medical certificate.
  - (C) The certificate of medical emergency shall be in writing, sent to the utility from the office of a licensed physician, and show clearly the name of the customer or individual whose illness is at issue; the Colorado medical identification number, phone number, name, and signature of the physician or health care practitioner acting under a physician's authority certifying the medical emergency. Such certification shall be incontestable by the utility as to the medical judgment, although the utility may use reasonable means to verify the authenticity of such certification.

**4408. Notice of Discontinuance.**

- (a) Except as provided in paragraphs (g) and (h) of this rule, a utility shall provide, by first class mail or by hand-delivery, written notice of discontinuance of service at least 15 days in advance of any proposed discontinuance of service. The heading shall contain, in bold font and capital letters, the following warning:
- THIS IS A FINAL NOTICE OF DISCONTINUANCE OF UTILITY SERVICE AND  
CONTAINS IMPORTANT INFORMATION ABOUT YOUR LEGAL RIGHTS AND  
REMEDIES. YOU MUST ACT PROMPTLY TO AVOID UTILITY SHUT OFF.**
- (b) The body of the notice of discontinuance under paragraph (a) of this rule shall at a minimum advise the customer of the following:
- (I) the reason for the discontinuance of service and of the particular terms of service and rule (if any) which has been violated;
  - (II) the amount past due for utility service, deposits, or other regulated charges, if any;

- (III) the date by which an installment payment plan must be entered into or full payment must be received in order to avoid discontinuance of service;
  - (IV) how and where the customer can pay or enter into an installment payment plan prior to the discontinuance of service;
  - (V) that the customer may avoid discontinuance of service by entering into an installment payment plan with the utility pursuant to rule 4404 as described in the utility's applicable tariff;
  - (VI) that the customer has certain rights if the customer or a member of the customer's household is seriously ill or has a medical emergency;
  - (VII) that the customer has the right to dispute the discontinuance directly with the utility by contacting the utility, and how to contact the utility toll-free from within the utility's service area;
  - (VIII) that the customer has the right to make an informal complaint to the Commission in writing, by telephone, or in person, along with the Commission's address and local and toll-free telephone number;
  - (IX) that the customer has the right to file a formal complaint, in writing, with the Commission pursuant to rule 1302 and that this formal complaint process may involve a formal hearing;
  - (X) that in conjunction with the filing of a formal complaint, the customer has a right to file a motion for a Commission order ordering the utility not to disconnect service pending the outcome of the formal complaint process and that the Commission may grant the motion upon such terms as it deems reasonable, including but not limited to the posting of a deposit or bond with the utility or timely payment of all undisputed regulated charges;
  - (XI) that if service is discontinued for non-payment, the customer may be required, as a condition of restoring service, to pay reconnection and collection charges in accordance with the utility's tariff; and
  - (XII) that qualified low-income customers may be able to obtain financial assistance to assist with the payment of the utility bill and that more detailed information on that assistance may be obtained by calling the utility toll-free. The utility shall state its toll-free telephone number.
- (c) At the time it provides notice of discontinuance to the customer, a utility shall also provide written notice by first class mail or hand-delivery to any third-party the customer has designated in writing to receive notices of discontinuance or broken arrangement.
- (d) A discontinuance notice shall be printed in English and a specific language or languages other than English where the utility's service territory contains a population of at least ten percent who speak a specific language other than English as their primary language as determined by the latest U.S. Census information.

- (e) A utility shall explain and shall offer the terms of an installment payment plan to each customer who contacts the utility in response to a notice of discontinuance of service.
- (f) Following the issuance of the notice of discontinuance of service, and at least 24 hours prior to discontinuance of service, a utility shall attempt to give notice of the proposed discontinuance in person or by telephone both to the customer and to any third party the customer has designated in writing to receive such notices. If the utility attempts to notify the customer in person but fails to do so, it shall leave written notice of the attempted contact and its purpose.
- (g) If a customer has entered into an installment payment plan and has defaulted or allowed a new bill to remain unpaid past its due date, a utility shall provide, by first class mail or by hand-delivery, a written notice to the customer. The notice shall contain:
  - (I) a heading as follows: NOTICE OF BROKEN ARRANGEMENT
  - (II) statements that advise the customer:
    - (A) that the utility may discontinue service if it does not receive the monthly installment payment within ten days after the notice is mailed or hand-delivered;
    - (B) that the utility may discontinue service if it does not receive payment for the current bill within 30 days after its due date;
    - (C) that, if service is discontinued, the utility may refuse to restore service until the customer pays all amounts for regulated service more than 30 days past due and any collection or reconnection charges; and
    - (D) that the customer has certain rights if the customer or a member of the customer's household is seriously ill or has a medical emergency.
- (h) A utility is not required to provide notice under this rule if one of the following applies:
  - (I) the situation involves safety concerns;
  - (II) discontinuance is ordered by any appropriate governmental authority;
  - (III) either paragraph 4407(c) or 4407(d) applies; or
  - (IV) service, having been already properly discontinued, has been restored by someone other than the utility and the original cause for discontinuance has not been cured.
- (i) Where a utility knows that the service to be discontinued is used by customers in multi-unit dwellings, in places of business, or in a cluster of dwellings or places of business and the utility service is recorded on a single meter used either directly or indirectly by more than one unit, the utility shall issue notice as required in paragraphs (a) and (b) of this rule, except that:
  - (I) the notice period shall be 30 days;
  - (II) such notice may include the current bill;

- (III) the utility shall provide written notice to each individual unit, stating that a notice of discontinuance has been sent to the party responsible for the payment of utility bills for the unit and that the occupants of the units may avoid discontinuance by paying the next new bill in full within 30 days of its issuance and successive new bills within 30 days of issuance; and
- (IV) the utility shall post the notice in at least one of the common areas of the affected location.

**4409. Restoration of Service.**

- (a) Unless prevented from doing so by safety concerns, a utility shall restore, without additional fee or charge, any discontinued service which was not properly discontinued or restored as provided in rules 4407, 4408, and 4409.
- (b) Unless prevented by safety concerns, a utility shall restore service within 24 hours (excluding weekends and holidays), or within 12 hours if the customer pays any necessary after-hours charges established in tariffs, if the customer does any of the following:
  - (I) pays in full the amount for regulated charges shown on the notice and any deposit and/or fees as may be specifically required by the utility's tariff in the event of discontinuance of service;
  - (II) pays any reconnection and collection charges specifically required by the utility's tariff, enters into an installment payment plan, and makes the first installment payment, unless the cause for discontinuance was the customer's breach of such an arrangement;
  - (III) presents a medical certification, as provided in subparagraph 4407(e)(IV);
  - (IV) demonstrates to the utility that the cause for discontinuance, if other than non-payment, has been cured.

**4410. Refunds.**

- (a) A utility shall file an application for Commission approval of a refund plan if it seeks to refund monies of an amount that exceeds one half of one percent of the utility's prior year's total gross revenues as reported to the Commission in its most recent annual report. The utility may refund amounts to the appropriate customers or classes of customers of less than one half of one percent of the utility's prior year's gross revenues without Commission approval; however, such refunds are required to be noted in the utility's annual report when filed with the Commission pursuant to paragraph 4006(a).
- (b) The application for approval of a refund plan shall include, in the following order and specifically identified, the following information either in the application or in the appropriately identified attachments:
  - (I) all the information required in paragraphs 4002(b) and 4002(c);
  - (II) the reason for the proposed refund;

- (III) a detailed description of the proposed refund plan, including the type of utility service involved, the service area involved, the class(es) of customers to which the refund will be made, and the dollar amount (both the total amount and the amount to be paid to each customer class) of the proposed refund. The interest rate on the refund shall be the current interest rate in the applying utility's customer deposits tariff;
  - (IV) the date the applying utility proposes to start making the refund, which shall be no more than 60 days after the filing of the application; the date by which the refund will be completed; and the means by which the refund is proposed to be made;
  - (V) if applicable, a reference (by proceeding number, decision number, and date) to any Commission decision requiring the refund or, the order itself if the refund is to be made because of receipt of monies by the applying utility under the order of a court or of another state or federal agency;
  - (VI) a statement describing in detail the extent to which the applying utility has any financial interest in any other company involved in the refund plan;
  - (VII) a statement showing accounting entries under the Uniform System of Accounts; and
  - (VIII) a statement that, if the application is granted, the applying utility will file an affidavit verifying that the refund has been made in accordance with the Commission's decision.
- (c) A utility shall pay 90 percent of all undistributed balances, plus associated interest, to the energy assistance organization. For purposes of this rule, a refund is deemed undistributed if, after good faith efforts, a utility is unable to find the person entitled to a refund within the period of time fixed by the Commission in its decision approving the refund plan.
- (d) A utility shall pay an undistributed refund to the energy assistance organization within four months after the refund is deemed undistributed. A utility shall pay interest on an undistributed refund from the time it receives the refund until the refund is paid to the energy assistance organization. The interest rate shall be equal to the interest rate set by the Commission pursuant to paragraph 4403(m).
- (e) Whenever a utility makes a refund, it shall provide written notice to those customers that it believes may be master meter operators. The notice shall contain:
- (I) the definition of master meter operator, as set forth in these rules;
  - (II) a statement regarding a mater meter operator's obligation to do the following:
    - (A) to notify its end users of their right to claim, within 90 days, their proportionate share of the refund; and
    - (B) after 90 days, if the unclaimed balance exceeds \$100, to remit the unclaimed balance to the energy assistance organization.
- (f) A utility shall resolve all inquiries regarding a customer's undistributed refund and shall not refer such inquiries to the energy assistance organization.

- (g) If a utility has paid an undistributed refund to the energy assistance organization, a customer later makes an inquiry claiming that refund, and the utility resolves the inquiry by paying that refund to the customer, the utility may deduct the amount paid to the customer from future funds submitted to the energy assistance organization.

**4411. Low-Income Energy Assistance Act.**

- (a) Scope and applicability.
- (I) Rule 4411 is applicable to gas and combined gas and electric utility providers except those exempted under (II) or (III). Pursuant to §§ 40-8.7-101 through 111, C.R.S., utilities are required to provide an opportunity for their customers to contribute an optional amount through the customers' monthly billing statement.
- (II) Municipally owned gas or gas and electric utilities are exempt if:
- (A) the utility operates an alternative energy assistance program to support its low-income customers with their energy needs and self-certifies to the Organization through written statement that its program meets the following criteria:
- (i) the amount and method for funding of the program has been determined by the governing body; and
- (ii) the program monies will be collected and distributed in a manner and under eligibility criteria determined by the governing body for the purpose of residential energy assistance to customers who are challenged with paying energy bills for financial reasons, including seniors on fixed incomes, individuals with disabilities, and low-income individuals, or,
- (B) the governing body of the utility determines its service area has a limited number of people who qualify for energy assistance and self-certifies to the Organization via written statement such determination.
- (III) A municipally owned gas or gas and electric utility not exempt under subparagraph (a)(II) of this rule, is exempt if:
- (A) the utility designs and implements a procedure to notify all customers at least twice each year of the option to conveniently contribute to the Organization by means of a monthly energy assistance charge. Such procedure shall be approved by the governing utility. The governing body of such utility shall determine the disposition and delivery of the optional energy assistance charge that it collects on the following basis:
- (i) delivering the collections to the organization for distribution; or
- (ii) distributing the moneys under criteria developed by the governing body for the purpose set forth in subparagraph (a)(II)(A)(ii) of this rule;

- (B) alternatively, the utility provides funding for energy assistance to the Organization by using a source of funding other than the optional customer contribution on each customer bill that approximates the amount reasonably expected to be collected from an optional charge on customer's bills.
  - (IV) A municipally gas or gas and electric utility that is exempt under subparagraph (a)(III) of this rule shall be entitled to participate in the Organization's low-income assistance program.
  - (V) Gas or gas and electric utilities that desire a change in status must inform the Organization and file a notice to the Commission within 30 days prior to expected changes.
- (b) Definitions. The following definitions apply only in the context of rule 4411. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.
- (I) "Alternative energy assistance program" means a program operated by a municipally owned electric and gas utility or rural electric cooperative that is not part of the energy assistance program established pursuant to this statute.
  - (II) "Customer" means the named holder of an individually metered account upon which charges for electricity or gas are paid to a utility. "Customer" shall not include a customer that receives electricity or gas for the sole purpose of reselling the electricity or gas to others.
  - (III) "Energy assistance program" or "Program" means the Low Income Energy Assistance Program created by § 40-8.7-104, C.R.S., and designed to provide financial assistance, residential energy efficiency, and energy conservation assistance.
  - (IV) "Organization" means Energy Outreach Colorado, a Colorado nonprofit corporation.
  - (V) "Remittance device" means the section of a customer's utility bill statement that is returned to the utility company for payment. This includes but is not limited to paper payment stubs, web page files used to electronically collect payments, and electronic fund transfers.
  - (VI) "Utility" means a corporation, association, partnership, cooperative electric association, or municipally owned entity that provides retail electric service or retail gas service to customers in Colorado. "Utility" does not mean a propane company.
- (c) Plan implementation and maintenance.
- (I) Except as provided in paragraph 4411(a), each utility shall implement and maintain a customer opt-in contribution mechanism. The utility's opt-in mechanism shall include, at minimum, the following provisions.
    - (A) A description of the procedures the utility will use to notify its customers, including those customers that make payments electronically, about the opt-in provision. Utilities may combine their efforts to notify customers into a single

state-wide or region-wide effort consistent with the participating utilities communication programs. Each participating utility shall clearly identify its support of the combined communications program, with its corporate name and/or logo visible to the intended audience.

- (B) A description of the additional efforts the utility will use to inform its customers about the program to ensure that adequate notice of the opt-in provision is given to all customers. Notification shall include communication to all customers that the donation and related information will be passed through to the Organization.
- (C) A description of the check-off mechanism that will be displayed on the monthly remittance device to solicit voluntary donations. The remittance device shall include, at minimum, check-off categories of five dollars, ten dollars, twenty dollars, and “other amount”. The remittance device must also note the name of the program as the “voluntary energy assistance program,” or if the utility is unable to identify the name of the program individually, the utility shall use a general energy assistance identifier approved by the Commission.
- (D) A description or an example of how the utility will display the voluntary contribution as a separate line item on the customer’s monthly billing statement and how the voluntary contribution will be included in the total amount due. The line item must identify the contribution as “voluntary”.
- (E) A description of the notification process that the utility will use to ensure that once a utility customer opts into the program, the energy assistance contribution will be assessed on a monthly basis until the customer notifies the utility of the customer’s desire to stop contributing. The utility shall describe how it will manage participation in the program when customers miss one or more voluntary payment, or pay less than the pre-selected donation amount.
- (F) Identification of the procedures the utility will use to notify customers of their ability to cancel or discontinue voluntary contributions along with a description of the mechanism the utility will use to allow customers who make electronic payments to discontinue their participation in the opt-in program.
- (G) A description of the procedures the utility will use, where feasible, to notify customers participating in the program about the customer’s ability to continue to contribute when the customer changes their address within the utility’s service territory.
- (H) A description of the method the utility will use to provide clear, periodic, and cost-effective notice of the opt-in provision to its customers at least twice per year. Acceptable methods include, but are not limited to, bill inserts, statements on the bill or envelope, and other utility communication pieces.
- (I) A description of the start-up costs that the utility incurred in connection with the program along with supporting detailed justification for such costs. The description should include the utility’s initial costs of setting up the collection mechanism and reformatting its billing systems to solicit the optional contribution



but shall not include the cost of any notification efforts by the utility. Utilities may elect to recover all start-up costs before the remaining moneys generated by the program are distributed to the Organization or over a period of time from the funds generated by the program, subject to Commission review and approval.

- (J) An estimate of the on-going costs that the utility expects to incur in connection with the program along with supporting detailed justification for such costs. This estimate shall not include the cost of any notification efforts by the utility.
  - (K) A detailed justification for the costs identified in (I) and (J). As stated in § 40-8.7-104(3), C.R.S., the costs incurred must be reasonable in connection with the program.
  - (L) Utilities shall recover the start up cost and on-going cost of administration associated with the program from funds generated from the program. Insert and notification costs shall be considered in the utility's cost of service.
  - (M) A description of the procedures the utility will use to account for and process program donations separately from customer payments for utility services.
- (II) Each utility shall participate in the energy assistance program consistent with its plan approved by the Commission and shall provide the opportunity for its customers to make an optional energy assistance contribution on the monthly remittance device on their utility bill.
  - (III) The utility may submit an application to the Commission no later than April 1 of each year for approval of reimbursement costs the utility incurred for the program during the previous calendar year. Such application shall include a proposed schedule for the reimbursement of these costs to the utility. The applications shall include detailed supporting justification for approval of these costs. Such detailed justification includes, but is not limited to, copies of invoices and time sheets. Such applications shall not seek reimbursement of costs related to notification efforts. Participating utilities may request reimbursement costs for such notification efforts in base rate filings, subject to Commission review and approval.
  - (IV) A utility may seek modification of its initial plan or subsequent plans by filing an application with the Commission.
- (d) Fund administration.
- (I) At a minimum, each utility shall transfer the funds collected from its customers under the energy assistance program to the organization under the following schedule:
    - (A) for the funds collected during the period of January 1 to March 31 of each year, the utility shall transfer the collected funds to the Organization before May 1 of such year;

- (B) for the funds collected during the period of April 1 to June 30 of each year, the utility shall transfer the collected funds to the Organization before August 1 of such year;
  - (C) for the funds collected during the period of July 1 to September 30 of each year, the utility shall transfer the collected funds to the Organization before November 1 of such year;
  - (D) for the funds collected during the period of October 1 to December 31 of each year, the utility shall transfer the collected funds to the Organization before February 1 of the next year; and
  - (E) each utility shall maintain a separate accounting for all energy assistance program funds received by customers.
- (II) Each utility shall provide the organization with the following information.
- (A) How the funds collected for the previous calendar year were generated, including the number of customers participating in the program. Such report shall include a summary of the number of program participants and funds collected by month, and shall be provided by February 1 of each year.
  - (B) At each time funds are remitted, a listing of all program participants including the donor's name, billing address, and monthly donation amount. The participant information provided to the organization shall be used exclusively for complying with the requirements of § 40-8.7-101, C.R.S., et seq. and state and federal laws.
- (III) The Public Utilities Commission shall submit, as necessary, a bill for payment to the Organization for any administrative costs incurred pursuant to the program.
- (IV) The organization shall provide the Office of Consumer Counsel and the Public Utilities Commission with a copy of the written report that is described in § 40-8.7-110, C.R.S. This report shall not contain individual participant information.
- (e) Prohibition of disconnection. Utilities shall not disconnect a customer's gas service for non-payment of optional contribution amounts.

**4412. Gas Service Low-Income Program.**

- (a) Scope and applicability.
  - (I) Gas utilities with Colorado retail customers shall provide low-income energy assistance by offering rates, charges, and services that grant a reasonable preference or advantage to residential low-income customers, as permitted by § 40-3-106, C.R.S.
  - (II) Rule 4412 is applicable to investor-owned gas utilities subject to rate regulation by the Commission.

- (b) Definitions. The following definitions apply only in the context of rule 4412. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.
- (I) “Administrative cost” means the utility’s direct cost for labor (to include the cost of benefit loadings), materials, and other verifiable expenditures directly related to the administration and operation of the program not to exceed ten percent of the total cost of program credits applied against bills for current usage and pre-existing arrearages or \$10,000, whichever amount is greater.
  - (II) “Affordable percentage of income payment” means the amount of the participant’s annual bill deemed affordable under subparagraph 4412(e)(I).
  - (III) “Arrearage” means the past-due amount appearing, as of the date on which a participant newly enters the program, on the then most recent prior bill rendered to a participant for which they received the benefit of service.
  - (IV) “Colorado Energy Office” (CEO) means the Colorado Energy Office created in § 24-38.5-101, C.R.S.
  - (V) “Eligible low-income customer” means a residential utility customer who meets the household income thresholds pursuant to paragraph 4412(c).
  - (VI) “Fixed credit” means an annual bill credit established at the beginning of a participant’s participation in a program each year delivered as a monthly credit on each participant’s bill. The fixed credit is the participant’s full annual bill minus the participant’s affordable percentage of income payment obligation on the full annual bill.
  - (VII) “Full annual bill” means the current consumption of a participant billed at standard residential rates. The full annual bill of a participant is comprised of two parts: (1) that portion of the bill that is equal to the affordable percentage of income payment; and (2) that portion of the bill that exceeds the affordable percentage of income payment.
  - (VIII) “LEAP” means Low-Income Energy Assistance Program, a county-run, federally-funded, program supervised by the Colorado Department of Human Services, Division of Low-Income Energy Assistance.
  - (IX) “LEAP participant” means a utility customer who at the time of applying to participate in a program has been determined to be eligible for LEAP benefits by the Department during either the Department’s current six-month (November 1 – April 30) LEAP application period, if that period is open at the time the customer applies for program participation; or (the Department’s most recently closed six-month (November 1 – April 30) LEAP application period, if that period is closed at the time the customer applies to participate in the program and the Department’s next six-month (November 1 – April 30) LEAP application period has not yet opened, provided, however, that in order to retain status as a LEAP participant under this definition, the utility customer must apply to the Department during the Department’s next six-month (November 1 – April 30) LEAP benefit application period and be determined eligible for such benefits.

- (X) “Non-participant” means a utility customer who is not receiving low-income assistance under rule 4412.
  - (XI) “Participant” means an eligible low-income residential utility customer who is granted the reasonable preference or advantage through participation in a gas service low-income program.
  - (XII) “Percentage of Income Payment Plan” (PIPP) means a payment plan for participants that does not exceed an affordable percentage of their household income as set forth in subparagraph 4412(e)(I).
  - (XIII) “Program” means a gas service low-income program approved under rule 4412.
  - (XIV) “Program credits” means the amount of benefits provided to participants to offset the unaffordable portion of a participant’s utility bill and /or dollar amounts credited to participants for arrearage forgiveness.
  - (XV) “Unaffordable portion” means the amount of the estimated full annual bill that exceeds the affordable percentage of income payment.
- (c) Participant eligibility. Eligible participants are limited to those with a household income at or below 185 percent of the current federal poverty level, or, if the utility applies individual LEAP benefits to offset the costs of the unaffordable portion of the participating customer’s utility bill, the percent of the current federal poverty level set by the Colorado Department of Human Services, Division of Low-income Energy Assistance for eligibility in the LEAP program.
- (I) Gas utilities may obtain federal annual poverty level income amounts based on household size on the Colorado Department of Human Services, Division of Low Income Energy Assistance website at <https://sites.google.com/a/state.co.us/cdhs-leap/program-eligibility>.
  - (II) The utility shall obtain household income information from LEAP.
  - (III) If a participant’s household income is \$0, the utility may establish a process that verifies income on a more frequent basis.
  - (IV) Program participants shall not be required to make payment on their utility account as a condition of entering into the program.
- (d) Enrollment. Utilities shall be responsible for the methods by which participant enrollment in their approved low income program is obtained and sustained, however the utility should engage in enrollment processes that are efficient and attempt to maximize the potential benefits of participation in the low income program by low income customers.

(e) Payment plan.

- (I) Participant payments for natural gas bills rendered to participants shall not exceed an affordable percentage of income payment. For accounts for which natural gas is the primary heating fuel, participant payments shall be no lower than two percent and not greater than three percent of the participant's household income.
- (II) In the event that a primary heating fuel for any particular participant has been identified by LEAP, that determination shall be final.
- (III) Notwithstanding the percentage of income limits established in subparagraph 4412(e)(I), a utility may establish minimum monthly payment amounts for participants with household income of \$0, provided that the participant's minimum payment for a natural gas account shall be no more than \$10.00 a month.
- (IV) Full annual bill calculation. The utility shall be responsible for estimating a participant's full annual bill for the purpose of determining the unaffordable portion of the participant's full annual bill delivered as a fixed credit on the participant's monthly billing statement.
- (V) Fixed credit benefit. The fixed credit shall be adjusted during a program year in the event that standard residential rates, including commodity or fuel charges change to the extent that the full annual bill at the new rates would differ from the full annual bill upon which the fixed credits are currently based by 25 percent or more.
- (VI) Levelized budget billing participation. A utility shall enroll participants in its levelized budget billing program as a condition of participation in the program. Should a participant fail to meet monthly bill obligations and be placed by a utility in its regular delinquent collection cycle, the utility may remove the participant from levelized budget billing in accordance with the utility's levelized budget billing tariff.
- (VII) Arrearage credits.
  - (A) Arrearage credits shall be applied to pre-existing arrearages.
  - (B) Arrearage credits shall be sufficient to reduce, when combined with participant copayments, if any, the pre-existing arrearages to \$0.00 over a period not less than one month and not more than twenty-four months.
  - (C) Application of an arrearage credit to a participant account may be conditioned by the utility on one or more of the following:
    - (i) the receipt of regular participant payments toward bills for current usage;  
or
    - (ii) the payment of a participant copayment toward the arrearages so long as the participant's copayment total dollar amount does not exceed one percent of gross household income.

- (D) Should the participant exit the program prior to the full forgiveness of all pre-existing arrearages, the amount of remaining pre-existing arrearages shall become due in accordance with the utilities tariff filed under rules 4401, 4407, and 4408.
  - (E) Pre-existing arrears under this subparagraph shall not serve as the basis for the termination of service for nonpayment or as the basis for any other utility collection activity while the customer is participating in the program.
  - (F) A participant may receive arrearage credits under this section even if that participant does not receive a credit toward current bills, if the participant enters into and maintains a levelized budget billing plan.
- (VIII) Portability of benefits. A participant may continue to participate without reapplication should the participant change service addresses, but remain within the service territory of the utility providing the benefit, provided that the utility may make necessary adjustments in the levelized budget billing amount to reflect the changed circumstances. A participant who changes service addresses and does not remain within the service territory of the utility providing the benefit must reapply to become a participant at the participant's new service address.
- (IX) Payment default provisions. Failure of a participant to make his or her monthly bill payments will result in a utility placing the participant in its regular collection cycle. Missed, partial or late payments shall not result in the removal of a participant from the program.
- (f) Program implementation.
- Each utility shall maintain effective terms and conditions in its tariffs on file with the Commission describing its low-income program.
- (g) Cost recovery.
- (I) Each utility shall include in its low income tariff terms and conditions how costs of the program will be recovered.
  - (II) Program cost recovery.
    - (A) Program cost recovery shall be based on a fixed monthly fee.
    - (B) The maximum impact on residential rates shall be no more than \$00.31 per month.
    - (C) In order to determine monthly rates applicable to rate classes other than residential, program costs shall be allocated to each retail rate based on each rate class's share of the test year revenue requirement established in the utility's last Phase II rate case, or under another reasonable methodology supported by quantifiable information. The monthly rate per this subparagraph to be charged each rate schedule customer shall be clearly stated on a tariff sheet.

- (D) Utilities shall separately account for the cumulative program cost recovery and cumulative program and administrative costs to determine if the net of program cost recovery and program and administrative cost are in balance during the program year.
  - (i) Beginning October 31, 2018 and in each year thereafter, the utility shall file a report with the Commission in the most recent miscellaneous proceeding for annual low-income filings detailing the net difference between program cost recovery and program costs as of September 30 of each year.
    - (1) Should the net difference of program cost recovery over program costs be greater than 50 percent derived in (ii) above, either positive or negative, and the utility is not currently at the maximum impact for non-participants, the utility shall file with the Commission an advice letter and tariff pages seeking approval for the rates determined in subparagraph 4412(g)(II)(D) in order to bring the projected recovery in balance for the ensuing 12 month period. The revised Residential charge shall not exceed the maximum impact for non-participants in subparagraph 4412(g)(II)(C).
- (III) The following costs are eligible for recovery by a utility as program costs:
  - (A) program credits or discounts applied against bills for current usage;
  - (B) program credits applied against pre-existing arrearages;
  - (C) program administrative costs; and
  - (D) Commission-sponsored program evaluation costs required under paragraph 4412(k).
- (IV) The utility shall apply, as an offset to cost recovery, all program expenses attributable to the program. Program expenses include utility operating costs; changes in the return requirement on cash working capital for carrying arrearages; changes in the cost of credit and collection activities directly related to low-income participants; and changes in uncollectable account costs for these participants.
- (V) LEAP grants.
  - (A) The utility shall apply energy assistance grants provided to the participant by the LEAP program to the dollar value of credits granted to individual program participants.
  - (B) A utility shall apply any energy assistance benefit granted to the participant by LEAP to that portion of the program participant's full annual bill that exceeds the participant's affordable percentage of income payment.

- (C) If the dollar value of the energy assistance grant is greater than the dollar value of the difference between the program participant's full annual bill and the participant's affordable percentage of income payment, the dollar amount by which the energy assistance grant exceeds the difference will be applied:
    - (i) first, to any pre-existing arrearages that at the time of the energy assistance grant continues to be outstanding; and
    - (ii) second, to the account of the program participant as a benefit to the participant.
  - (D) No portion of an energy assistance or LEAP grant provided to a program participant may be applied to the account of a participant other than the participant to whom the energy assistance grant was rendered.
- (h) Other programs. In addition to the utility's low-income program, with Commission approval, a utility may offer other rate relief options to eligible households.
- (I) Other programs offered by the utility under rule 4412 must be intended to reach low-income households that do not substantially benefit from the provisions of the low-income program. Such programs may take the form of discount rates, tiered discount rates or other direct bill relief methods where the low-income household benefitting from the program is granted a reasonable preference in tariffed rates assessed to all residential utility customers.
  - (II) Cost recovery for other programs combined with the Percentage of Income Payment Plan shall not exceed the maximum impact on residential rates described in subparagraph 4412(g)(II)(C).
- (i) Energy efficiency and weatherization.
- (I) The utility shall provide all program participants with information on energy efficiency programs offered by the utility or other entities and existing weatherization programs offered by the state of Colorado or other entities.
  - (II) The utility shall provide the Colorado Energy Office with the name and service address of participant households for which annual natural gas usage exceeds 600 therms annually.
- (j) Stakeholder engagement. A utility shall conduct annual meetings with low-income stakeholders for the purpose of seeking solutions to issues of mutual concern and aligning program practices with the needs of customers and other stakeholders.
- (k) Program evaluation. A triennial evaluation of the program provisions under rule 4412 beginning in 2019 shall be undertaken in order to review best practices in similar low income assistance programs in existence in other regulatory jurisdictions, as well as evaluate operation of each utility's program for effectiveness in achieving optimum support being provided to low income participants. The evaluation shall also recommend modifications if available that improve the delivery of benefits to participants and increase the efficiency and effectiveness of each program as they exist at the point of evaluation.



- (I) Procurement of the third-party vendor that will perform the evaluation will be undertaken by the Colorado Energy Office. The CEO shall seek the involvement of interested stakeholders including, but not limited to, Commission staff, all Commission regulated electric and gas utilities, LEAP, the Office of Consumer Counsel, and Energy Outreach Colorado in the design of the requirements regarding study focus and final reporting.
  - (II) Approval of the third-party vendor shall be the responsibility of the Commission. The CEO shall file with the Commission in the most recent annual report proceeding, a request for approval of the contract of the vendor selected. The Commission shall review and act on the request within 30 days.
  - (III) \$00.0013 per customer per month shall be set aside by the utility starting in the 2016-2017 program year in order to cover the cost of the program evaluation described in paragraph 4412(k).
  - (IV) The dollars resulting from the \$00.0013 charge shall be recovered as a program cost under subparagraph 4412(g)(III).
  - (V) The evaluation will be filed by Commission staff in the most recent miscellaneous proceeding for annual low income filings.
  - (VI) Staff and the CEO will assess the individual utilities' deferred balances set aside for the program evaluation starting in 2019 at the conclusion of the third program year and each three years thereafter and will determine the amounts each utility is to remit to the third party evaluator based on the contractual terms approved by the Commission for the evaluation.
- (I) Annual report. No later than December 31, of each year the utility shall file a report in the most recent miscellaneous proceeding established by the Commission to receive annual low income filings using the form available on the Commission's website, based on the 12-month period ending October 31 containing the following information:
- (I) monthly information on the program including number of participants, amount of benefit disbursement, type of benefit disbursement, LEAP benefits applied to the unaffordable portion of participant's bills, administrative costs, and revenue collection;
  - (II) the number of applicants for the program;
  - (III) the number of applicants qualified for the program;
  - (IV) the number of participants;
  - (V) the average assistance provided, both mean and median;
  - (VI) the maximum assistance provided to an individual participant;
  - (VII) the minimum assistance provided to an individual participant;

- (VIII) total cost of the program and the average rate impact on non-participants by rate class, including impact based on typical monthly consumption of both its residential and small business customers;
- (IX) the number of participants that had service discontinued as a result of late payment or non-payment, and the amount of uncollectable revenue from participants;
- (X) an estimate of utility savings as a result of the implementation of the program (e.g., reduction in trips related to discontinuance of service, reduction in uncollectable revenue, etc.);
- (XI) the average monthly and annual total natural gas consumption in PIPP participants' homes;
- (XII) the average monthly and annual total natural gas consumption in the utility's residential customer's homes;
- (XIII) the number of program participants referred to the weatherization program;
- (XIV) a description of the ways in which the program is being integrated with existing energy efficiency of DSM programs offered by the utility;
- (XV) a description of the ways in which the program is being integrated with existing weatherization programs offered by the state of Colorado;
- (XVI) a description of program outreach strategies and metrics that illustrate the effectiveness of each outreach strategy;
- (XVII) the number of participants at the start of the program year that the utility removed for any reason, the number of potential participants rejected because of the existence of a cap on the program, the period of arrearage time from date participants became eligible and were granted arrearage forgiveness, and the number of participants who came back as eligible participants in the program year after being eligible in a prior program year and were provided arrearage credits in the program year; and
- (XVIII) a narrative summary of the utility's recommended program modifications based on report findings.

**4413. – 4499. [Reserved].**

## **UNREGULATED GOODS AND SERVICES**

### **4500. Overview and Purpose.**

The purpose of these rules is to establish cost assignment and allocation principles to assist the Commission in setting just and reasonable rates and to ensure that utilities do not use ratepayer funds to subsidize non-regulated activities, in accordance with § 40-3-114, C.R.S. In order to promote these purposes, these rules also specify information that utilities must provide to the Commission. In providing for review of a utility's specific cost allocations in other states and jurisdictions, the rules merely

contemplate a methodology to allow interested parties to obtain complete information regarding cost allocations. These rules do not expressly or implicitly allow this Commission to order a utility to revise its cost allocations in other jurisdictions or states.

**4501. Definitions.**

The following special definitions apply only to rules 4501 through 4505. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- (a) “Activity” means a business activity, product or service whether offered by a Colorado utility, a division of a Colorado utility, or an affiliate of a Colorado utility.
- (b) “Allocate” or “Allocated” or “Cost Allocation” means to distribute a joint or common cost to or from more than one activity or jurisdiction.
- (c) “Assigned Costs” or “Cost Assignment” means a cost that is specifically identified with a particular activity or jurisdiction and charged directly to that activity or jurisdiction. At no point in the process of making the cost assignment is an allocation applied.
- (d) “Cost Assignment and Allocation Manual” (CAAM) means the indexed document filed by a utility with the Commission that describes and explains the cost assignment and allocation methods the utility uses to segregate and account for revenues, expenses, assets, liabilities, and rate base cost components assigned or allocated to Colorado jurisdictional activities. It includes the cost assignment and allocation methods to segregate and account for costs between and among jurisdictions, between regulated and non-regulated activities, and between and among utility divisions.
- (e) “Division” means an activity conducted by a Colorado utility but not through a legal entity separate from the Colorado utility. It includes the electric, gas, or thermal activities of a Colorado utility and any non-regulated activities provided by the Colorado utility.
- (f) “Fully Distributed Cost” (FDC) means the process of segregating, assigning, and allocating the revenues, expenses, assets, liabilities and rate base amounts recorded in the utility’s accounting books and records using cost accounting, engineering, and economic concepts, methods and standards. Fully distributed cost includes a return on investment in cases where assets are used.
- (g) “Fully Distributed Cost Study” is a cost study that reflects the result of the fully distributed revenues, expenses, assets, liabilities and rate base amounts for the Colorado utility to and from the different activities, jurisdictions, divisions, and affiliates using cost accounting, engineering, and economic concepts, methods, and standards.
- (h) “Incidental Services” means non-tariff or non-regulated services that have traditionally been offered incidentally to the provisions of tariff services where the revenues for all such services do not exceed:
  - (l) The greater of \$100,000 or one percent of the provider’s total annual Colorado operating revenues for regulated services; or,

- (II) Such amount established by the Commission considering the nature and frequency of the particular service.
- (i) “Jurisdictional” means having regulatory rate authority over a utility. Jurisdiction can be at a state or federal level.
- (j) “Regulated activity” means any activity that is offered as a public utility service as defined in Title 40, Articles 1 to 7 C.R.S., and is regulated by the Commission or regulated by another state utility commission or the FERC, or any non-regulated activity which meets the criteria specified in rules 4502(g).
- (k) “Non-regulated activity” means any activity that is not offered as a public utility service as defined in Title 40, Articles 1 to 7, C.R.S., and is not regulated by this Commission or another state utility commission or the FERC.
- (l) “Transaction” means the activity that results in the provision of products, services, or assets by one division or an affiliate to another division or an affiliate.

**4502. Cost Assignment and Allocation Principles.**

In determining fully distributed cost, the utility shall apply the following principles (listed in descending order of required application in paragraphs 4502 (a), (b) and (c) below).

- (a) Tariff services provided to an activity will be charged to the activity at the tariff rates.
- (b) If only one activity or jurisdiction causes a cost to be incurred, that cost shall be directly assigned to that activity or jurisdiction.
- (c) Costs that cannot be directly assigned to either regulated or non-regulated activities or jurisdictions will be described as common costs. Common costs shall be grouped into homogeneous cost categories designed to facilitate the proper allocation of costs between regulated and non-regulated activities or jurisdictions. Each cost category shall be fairly and equitably allocated between regulated and non-regulated activities or jurisdictions in accordance with the following principles.
  - (I) Cost causation. All activities or jurisdictions that cause a cost to be incurred shall be allocated a portion of that cost. Direct assignment of a cost is preferred to the extent that the cost can easily be traced to the specific activity or jurisdiction.
  - (II) Variability. If the fully distributed cost study indicates a direct correlation exists between a change in the incurrence of a cost and cost causation, that cost shall be allocated based upon that relationship.
  - (III) Traceability. A cost may be allocated using a measure that has a logical or observable correlation to all the activities or jurisdictions that cause the cost to be incurred.
  - (IV) Benefit. All activities or jurisdictions that benefit from a cost shall be allocated a portion of that cost.

- (V) Residual. The residual of costs left after either direct or indirect assignment or allocation shall be allocated based upon an appropriate general allocator to be defined in the utility's CAAM.
- (d) For cost assignment and allocation purposes, the value of all transactions from the Colorado utility to a non-regulated activity shall be determined as follows:
  - (I) if the transaction involves a product or service provided by the utility pursuant to tariff, the value of the transaction shall be at the tariff rate;
  - (II) if the transaction involves a product or service that is not provided pursuant to a tariff, the value of the transaction shall be the higher of the utility's fully distributed cost or market price. Market price shall be either the price charged by the utility, or if this condition cannot be met, the lowest price charged by another person for a comparable product or service; or
  - (III) if the transaction involves the sale of an asset, the value of the transaction shall be the higher of net-book cost or market price. If the transaction involves the use of an asset, the value of the transaction shall be the higher of fully distributed cost or market price. Market price shall be either the price charged by the utility or if this condition cannot be met, the lowest price charged by another person in the market for the sale or use of a comparable asset, when such prices are publicly available.
- (e) For cost assignment and allocation purposes, the value of all transactions from a non-regulated activity to the utility shall be determined as follows:
  - (I) if the transaction involves a product or service that is not provided pursuant to a tariff, the value of the transaction shall be the lower of the fully distributed cost or the market price except if the transaction results from a competitive solicitation process then the value of the transaction shall be the winning bid price. Fully distributed cost in this circumstance, shall be the cost that would be incurred by the utility to provide the service internally. Market price shall be either the price charged by the supplying non-regulated activity or if that condition is not met, the lowest price charged by other persons in the market for a comparable product or service, when such prices are publicly available; or
  - (II) if the transaction involves the sale of an asset, the value of the transaction shall be the lower of net-book cost or market price. If the transaction involves the use of an asset, the value of the transaction shall be at the lower of fully distributed cost or market price. Market price shall be either the price charged by the non-regulated activity or, if this condition cannot be met, the lowest price charged by another person in the market for the sale or use of a comparable asset, where such prices are publicly available.
- (f) If it is impracticable for the utility to establish a market price pursuant to paragraphs (d) or (e), the utility shall provide a statement to that effect, including its reasons in its' fully distributed cost study as well as its proposed method and amount for valuing the transaction. Parties in a Commission proceeding retain the right to advocate alternative market prices pursuant to paragraphs (d) and (e).

- (g) A utility may classify non-jurisdictional services as regulated if the services are rate-regulated by another agency (i.e., another state utility commission or the FERC) and where there are agency-accepted principles or methods for the development of rates associated with such services. This rule may apply, for example, to a provider's wholesale sales of electric power and energy. For such services, the utility shall identify the services in its manual, and account for the revenues, expenses, assets, liabilities, and rate base associated with these services as if these services are regulated.
- (h) For cost assignment and allocation purposes, the value of all transactions between regulated divisions within a utility shall be determined as follows:
  - (I) if the transaction involves a service provided by the utility pursuant to tariff, the value of the transaction shall be at the tariff rate, or
  - (II) if the transaction involves a service or function that is not provided pursuant to a tariff, the value of the transaction shall be at cost.
- (i) If the utility offers a service that is a combination of regulated and non-regulated activities (i.e., a bundled service), the utility shall assign and/or allocate costs to the regulated and non-regulated activities separately.
- (j) A utility may classify incidental activities as regulated activities. If an incidental activity is classified as a regulated activity, the utility shall clearly identify the activity as an incidental activity, and account for the revenues, expenses, assets, liabilities and rate base items as if that activity were a regulated activity.
- (k) To the extent possible, all assigned and allocated costs between regulated and non-regulated activities should have an audit trail which is traceable on the books and records of the applicable regulated utility to the applicable accounts pursuant to the Federal Energy Regulatory Commission Uniform System of Accounts.
- (l) In a rate proceeding involving the calculation of revenue requirements, a complaint proceeding where cost assignments or allocations are at issue, or a proceeding where CAAM approval is sought, the utility or any party may advocate a cost allocation principle other than that already in use, if the Commission has already approved the principle for that cost. The party requesting the alternative approach shall have the burden of proving the need for an alternative principle and why the particular principle is appropriate for the particular cost.

**4503. Cost Assignment and Allocation Manuals.**

- (a) Each utility shall maintain on file with the Commission an approved indexed cost assignment and allocation manual which describes and explains the calculation methods the utility uses to segregate and account for revenues, expenses, assets, liabilities, and rate base cost components assigned or allocated to Colorado jurisdictional activities. It includes the calculation methods to segregate and account for costs between and among jurisdictions, between regulated and non-regulated activities, and between and among utility divisions.
- (b) Each utility shall include the following information in its CAAM.

- (I) A listing of all regulated or non-regulated divisions of the Colorado utility together with an identification of the regulated or non-regulated activities conducted by each.
  - (II) A listing of all regulated or non-regulated affiliates of the Colorado utility together with an identification of which affiliates allocate or assign costs to and from the Colorado utility.
  - (III) A listing and description of each regulated and non-regulated activity offered by the Colorado utility. The Colorado utility shall provide a description in sufficient detail to identify the types of costs associated with the activity and shall identify how the activity is offered to the public and identify whether the Colorado utility provides the activity in more than one state. If an activity is offered subject to tariff, the Colorado utility may identify the tariff and the tariff section that describes the service offering in lieu of providing a service description.
  - (IV) A listing of the revenues, expenses, assets, liabilities and rate base items by Uniform System of Accounts account number that the utility proposes to include in its revenue requirement for Colorado jurisdictional activities including those items that are partially allocated to Colorado as well as those items that are exclusively assigned to Colorado.
  - (V) A detailed description showing how the revenues, expenses, assets, liabilities and rate base items by account and sub-account are assigned and/or allocated to the Colorado utility's non-regulated activities, along with a description of the methods used to perform the assignment and allocations.
  - (VI) A description of each transaction between the Colorado utility and a non-regulated activity which occurred since the Colorado utility's prior CAAM was filed and, for each transaction, a statement as to whether, for this Commission's jurisdictional cost assignment and allocation purposes, the value of the transactions is at cost or market as applicable.
  - (VII) A description of the basis for how the assignment or allocation is made.
  - (VIII) If the utility believes that specific cost assignments or allocations are under the jurisdiction of another authority, the utility shall so state in its CAAM and give a written description of the prescribed methods. Nothing herein shall be construed to be a delegation of this Commission's ratemaking authority related to those assignments or allocations.
  - (IX) Any additional information specifically required by Commission order.
- (c) A utility may treat certain transactions as confidential pursuant to the Commission rules on confidentially.
  - (d) Following the initial approval of its CAAM, the utility shall file an updated CAAM in each rate case proceeding where revenue requirements are determined or every five years following approval of the CAAM then in effect, whichever is earlier.
  - (e) The utility may, at its discretion, file an application seeking Commission approval of updates to its CAAM at any time.

- (f) Whenever a utility files for approval of an update to its CAAM as a result of paragraph (d) or (e) above, the utility shall also simultaneously file a FDC study reflecting the results of the cost allocation methods in its updated manual.
- (g) Each utility shall maintain all records and supporting documentation concerning its CAAMs for so long as such manual is in effect or are subject to a complaint or any active proceeding involving cost allocation before the Commission for as long as such proceeding may be open.

**4504. Fully Distributed Cost Study.**

- (a) The utility shall submit its fully distributed cost study in both electronic and paper format simultaneously with filing its CAAM for all Colorado divisions and activities.
- (b) The utility shall prepare a FDC study that identifies all the non-regulated activities provided by each division in Colorado. The FDC study shall show the revenues, expenses assets, liabilities and rate base items assigned and allocated to each non-regulated activity. If the utility has more than one division (e.g., gas, electric, thermal or non-utility) in Colorado, the FDC study shall include a summary of all assigned and allocated costs by division.
- (c) In preparation of its FDC study, the utility shall complete an analysis of each non-regulated activity to identify the costs that are associated with and/or should be charged to each non-regulated activity to ensure each non-regulated activity is assigned and allocated the appropriate amount of revenues, expenses, assets, liabilities and rate base items.
- (d) If the CAAM is filed in connection with a rate case, the FDC study shall be based on the same test year used in the utility's rate case filing. The utility's FDC study shall include revenues, expenses, assets, liabilities and rate base items in order for the Commission to determine if all appropriate revenues, expenses, assets, liabilities and rate base items have been appropriately assigned and allocated, and to determine the utility's compliance with the principles established in rule 4502. For each assignment and allocation the utility shall:
  - (I) identify the revenues, expenses, assets, liabilities and rate base items by account number, sub-account number and account description; and
  - (II) for each account in (I) above, identify the assignment and allocation method used to assign and allocate costs in sufficient detail to verify the assignment and allocation method used to assign and allocate costs to Colorado divisions and activities is accurate and consistent with the utility's CAAM methodology and reference the CAAM section that describes the allocation; and
  - (III) provide the test year dollar itemized amounts of revenues, expenses, assets, liabilities, and rate base assigned and allocated to each Colorado division and non-regulated activity; the itemized amounts assigned and allocated to the Colorado utility for regulated activities; the itemized amounts assigned and allocated to the Colorado utility for Colorado non-regulated activities; and the itemized amounts assigned and allocated to other jurisdictions.



- (e) Each utility shall maintain all records and supporting documentation concerning its FDC study for so long as such study is in effect or are subject to a complaint or a proceeding before the Commission.

**4505. Disclosure of Non-regulated Goods and Services.**

Whenever a Colorado utility engages in the provision or marketing of non-regulated goods or services in Colorado that are not subject to Commission regulation, and the Colorado utility's name or logo is used in connection with the provision of such non-regulated goods and services in Colorado, there must be conspicuous, clear, and concise disclosure to prospective customers that such non-regulated goods and services are not regulated by the Commission. Such disclosure to prospective customers in Colorado shall be included in all Colorado advertising or marketing materials, proposals, contracts, and bills for non-regulated goods and services, regardless of whether the Colorado utility provides such non-regulated goods or services in Colorado directly or through a division or affiliate.

**4506. – 4599. [Reserved].**

**GAS COST ADJUSTMENT AND PRUDENCE REVIEW**

**4600. Overview and Purpose.**

Rules 4601 through 4609 are used by LDCs to revise gas rates on an expedited basis. These rules provide instructions for the filing of: gas cost adjustment applications; annual gas purchase plan submittals; and annual gas purchase reports. The purpose of the Gas Cost Adjustment is to enable LDCs, on an expedited basis, to reflect in their rates for gas sales and gas transportation services, as applicable, the increases or decreases in gas costs, including (but not limited to) gas commodity costs and upstream services costs. The purpose of the Gas Purchase Plan is to describe the LDC's plan for purchases of gas commodity and upstream services in order to meet the forecasted demand for sales gas service during each month of the gas purchase year. The purpose of the Gas Purchase Report is to present the LDC's actual purchases of gas commodity and upstream services during each month of the gas purchase year.

**4601. Definitions.**

The following definitions apply to rules 4600 through 4609 unless a specific statute or rule provides otherwise. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- (a) "Account No. 191" means an account under the Federal Energy Regulatory Commission System of Accounts used to accumulate actual under-or-over recovered gas supply costs.
- (b) "Base gas cost" means a rate component which is expressed in at least the accuracy of one mil (\$0.001) per Mcf or Dth which reflects the cost of gas commodity and upstream services, when applicable, included in the utility's base rates for sales gas and gas transportation service.
- (c) "Base rates" means the utility's currently-effective rates for sales gas and gas transportation service as authorized by the Commission in the utility's last general rate case.

- (d) "Current gas cost" means a rate component of the GCA which is expressed in at least the accuracy of one mil (\$0.001) per Mcf or Dth and which reflects the cost of gas commodity and upstream service projected to be incurred by the utility during the GCA effective period.
- (e) "Deferred gas cost" means a rate component of the GCA which is expressed in at least the accuracy of one mil (\$0.001) per Mcf or Dth and which is designed to amortize over the GCA effective period the under- or over-recovered gas costs reflected in the utility's Account No. 191 or other appropriate costs for a defined period such as a gas purchase year.
- (f) "Forecasted design peak day quantity" means the total quantity of gas commodity anticipated to be required to meet firm sales and firm gas transportation service demand on the utility's system on a design or historical peak day.
- (g) "Forecasted gas commodity cost" means the cost of gas commodity, including appropriate adjustments for storage gas injections and withdrawals and for exchange gas imbalances, which is projected to be incurred by the utility during the GCA effective period and which is determined by using forecasted gas purchase quantity and forecasted purchase prices.
- (h) "Forecasted gas purchase quantity" means the quantity of gas commodity the utility anticipates it will purchase during the GCA effective period, based upon the forecasted sales gas quantity, adjusted for system gas loss, use, or other anticipated variances.
- (i) "Forecasted purchase prices" means index prices, fixed prices, or other gas contracting price options used in the calculation of the forecasted gas commodity cost.
- (j) "Forecasted sales gas quantity" means the quantity of gas commodity projected to be sold by the utility during the GCA effective period, based upon the normalized quantity of gas commodity sales, adjusted for anticipated changes.
- (k) "Forecasted upstream service cost" means the total cost of upstream services projected to be incurred by the utility during the GCA effective period.
- (l) "Gas commodity throughput" means the amount of gas commodity flowing through the utility's jurisdictional gas facilities during a defined period of time.
- (m) "Gas cost adjustment" or "GCA" means the tariff mechanism by which a gas rate is adjusted to reflect increases or decreases in gas costs.
- (n) "GCA effective period" means the period of time that the GCA rate change is intended to be in effect before being superseded on the effective date of the next scheduled GCA.
- (o) "Gas purchase plan" (GPP) means a submittal pursuant to rule 4605 that describes the utility's planned purchases of gas commodity and upstream services to be used to meet sales gas demand during the gas purchase year.
- (p) "Gas purchase report" (GPR) means a report pursuant to rule 4607 which is filed with the Commission and which describes the utility's actual purchases of gas commodity and upstream services in order to meet sales gas demand during the gas purchase year.

- (q) "Gas purchase year" means a 12-month period from July 1 through June 30.
- (r) "Gas transportation service" means the delivery of gas commodity on the utility's pipeline system (either transmission or distribution) pursuant to any of the utility's gas transportation rate schedules on file with the Commission.
- (s) "Index price" means a published figure identifying a representative price of natural gas commodity available in a geographic area or at specific gas purchasing points during a specified time interval (i.e., daily, weekly, or monthly).
- (t) "Mil" means one-tenth of one cent (\$0.001).
- (u) "Normalized" means the process of adjusting gas quantities to reflect normal historic temperature based on National Oceanic and Atmospheric Administration data or other data as appropriate.
- (v) "Peak day" means a defined period (such as a 24 hour period or a three consecutive coincidental or non-coincidental day average), not less than 24 hours, during which gas commodity throughput is at its maximum level on the utility's system.
- (w) "Receipt point/area" means the point or group of points in a discrete geographic area, such as a supply basin, hub, or market area, at which the utility acquires title to the gas commodity purchased.
- (x) "Sales gas service" means the regulated sale of gas commodity by the utility to customers on the utility's jurisdictional gas system.
- (y) "Service level" means the type or level (whether base, swing, or peak) of gas supply service contracted for by the utility based upon the respective obligations of the supplier to deliver and sell, and the utility to take and purchase, gas commodity.
- (z) "Upstream services" means all transmission, gathering, compression, balancing, treating, processing, storage, and like services performed by others under contract with the utility for the purpose of effectuating delivery of gas commodity to the utility's jurisdictional gas facilities.

**4602. Schedule for Filings by Utilities.**

Utilities subject to rules 4600 through 4609 shall make the required filings in accordance with the following schedule:

- (a) October 1 filing schedule. Public Service Company of Colorado, and Atmos Energy Corporation, shall file with the Commission annual GCA applications with an effective date of October 1. Additional GCA applications may also be filed as necessary pursuant to paragraph 4603(c). The GPR for the preceding gas purchase year in which a GPP was filed shall be filed as a separate filing at the same time as the annual GCA application to be effective October 1.
- (b) November 1 filing schedule. Black Hills/Colorado Gas Utility Company, LP; Black Hills Gas Distribution, LLC; Durango Mountain Utilities; and Colorado Natural Gas, Inc. shall file with the Commission annual GCA applications with an effective date of November 1. Additional GCA applications may also be filed as necessary pursuant to paragraph 4603(c). The GPR for the

preceding gas purchase year in which a GPP was filed shall be filed as a separate filing at the same time as the annual GCA application to be effective November 1.

- (c) All utilities shall file their GPP submittal annually on or before June 1 for the next gas purchase year beginning July 1.

**4603. Gas Cost Adjustments.**

- (a) A utility shall file an application to adjust its GCA. The GCA application shall be filed pursuant to the schedule provided in rule 4602. A utility shall file a GCA application not less than two weeks in advance of the proposed effective date.
- (b) A GCA application shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) the information required by paragraphs 4002(b) and 4002(c); and
  - (II) the information required by rule 4604. Attachments 2, 3, 5 and 6 listed in rule 4604 shall be provided in written form and shall be provided electronically, in executable format with all cell formulas intact, using spreadsheet software that is compatible with software used by the Commission staff.
- (c) If the projected gas costs have changed from those used to calculate the currently effective gas cost or if a utility's deferred gas cost balance increases or decreases sufficiently, the utility may file an application to revise its currently effective GCA to reflect such changes, provided that the resulting change to the GCA equates to at least one cent (\$0.01) per Mcf or Dth.
- (d) Applicability of the GCA. The GCA shall be applied to all utility sales gas rate schedules. A utility engaged in the provision of gas transportation service may calculate a GCA that may be applied to transportation gas rate schedules in order to reflect appropriate costs. Absent a Commission decision, a utility engaged in the provision of gas transportation service shall not be required to calculate a transportation GCA factor.
- (e) Interest on under- or over-recovery. The amount of net interest accrued on the average monthly balance in Account No. 191 (whether positive or negative), is determined by multiplying the monthly balance by an interest rate equal to the Commission-authorized customer deposit rate for gas utilities. If net interest is positive, it will be excluded from the calculation of the deferred gas cost.
- (f) Price volatility risk management costs (hedging). Costs related to gas price volatility risk management for jurisdictional gas supply may be included for recovery through the GCA, if allowed by tariffs or by Commission decision. Such costs are subject to the prudence review and standard provided in rule 4607.
- (g) Calculation of the GCA. The GCA shall be calculated to at least the accuracy of one mil per Mcf or Dth pursuant to the following formula, subject to individual GCA rule variances granted by the Commission:

$$\text{GCA} = (\text{current gas cost} + \text{deferred gas cost}) - (\text{base gas cost}).$$

**4604. Contents of GCA Applications.**

- (a) A GCA application shall meet the following requirements.
- (I) Every application shall contain attachments 1 through 9. Attachments 10 through 12 shall be filed with the annual GCA application. The attachments shall meet the requirements set out in this rule.
  - (II) The attachments shall be organized in a manner that specifically references, and responds to, the requirements contained in each subparagraph of this rule.
  - (III) Cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment shall be submitted and provided to Commission staff at the same time as the application.
  - (IV) The application shall cross-reference the proceeding numbers of the associated GPP submittals.
  - (V) When preparing attachments 10 through 12, the rate base, net operating earnings, capital structure, and cost of capital shall be calculated in conformance with the regulatory principles authorized by the Commission in the utility's most recent general rate case, including all required pro forma adjustments.
  - (VI) An explanation of all pro forma adjustments shall be provided.
- (b) GCA attachment No. 1 - GCA Summary. This attachment shall clearly illustrate all of the following principles.
- (I) The impact the utility's currently effective GCA has on each sales gas customer class and, when applicable, the gas transportation rate class on a total dollar and mil (\$0.001, minimum) per Mcf or Dth basis.
  - (II) The impact the utility's proposed GCA has on each sales gas customer class and, when applicable, gas transportation rate class on a total dollar and mil (\$0.001, minimum) per Mcf or Dth basis; and
  - (III) The percent change in total bill for a customer of average usage for each sales gas customer class. This percent change in total bill calculation shall include an itemization of the monthly service and facility charge, base rates and GCA commodity components, and all other tariff charges on the customer bill.
- (c) GCA attachment No. 2 - Current Gas Cost Calculation. This attachment shall contain the calculation of the current gas cost and shall provide month-by-month information with respect to the forecasted gas commodity cost, forecasted gas purchase quantity, forecasted market prices, forecasted upstream service cost, and forecasted sales gas quantity.
- (I) The utility shall calculate current gas cost at least to the accuracy of the nearest mil (\$0.001) per Mcf or Dth according to the following formula, subject to individual GCA rule variances granted by the Commission:

current gas cost = (forecasted gas commodity cost + forecasted upstream service cost) / forecasted sales gas quantity.

- (II) The utility shall present all such information in a format comparable with, and corresponding to, the information forecasted in the utility's GPP submittal for each month of the GCA effective period, as required pursuant to rule 4606.
- (d) GCA attachment No. 3 - Deferred Gas Cost Calculation. This attachment shall contain the details of the utility's actual gas purchase costs and the calculation of deferred gas cost. In addition, this attachment shall provide month-by-month information detailing the activity in USOA Account No. 191 by subaccount and period as applicable, interest on under- or over-recovery, and all other included gas costs authorized for recovery in the GCA. The utility shall calculate deferred gas cost as the aggregate total of the under- or over-recovered gas costs reflected in its Account No. 191, or other approved gas costs, recorded at the close of business for each month of the period at issue (such as the previous gas purchase year), plus interest on under- or over-recovery (if net amount is negative), divided by forecasted sales gas quantity. The utility shall calculate deferred gas cost at least to the accuracy of the nearest mil per Mcf or Dth. Each cost a utility includes in the deferred gas cost calculation shall be itemized and clearly identified and itemized for applicability to the period at issue. In its annual GCA applications the utility shall reflect actual deferred costs for the most recent period ending June 30, or as otherwise approved by the Commission.
- (e) GCA attachment No. 4 - Current Tariff. This attachment shall contain the tariff pages which illustrate the gas cost components of the utility's currently-effective rates for sales gas service and, where applicable, gas transportation service.
- (f) GCA attachment No. 5 - Forecasted Gas Transportation Demand. This attachment applies only to utilities that have a GCA component within their authorized rates for gas transportation service. This attachment shall provide the following information, with all demand forecast information provided on a Mcf or Dth basis:
- (I) a forecast of gas commodity throughput attributable to gas transportation service for each month of the GCA effective period; and
  - (II) a forecast of firm backup supply demand quantities (to the extent the utility has such service) under the utility's firm gas transportation service agreements for each month of the GCA effective period.
- (g) GCA attachment No. 6 - current gas cost allocations. This attachment shall fully explain and justify the method(s) used to do each of the following:
- (I) allocate the costs associated with the gas commodity and upstream services to each specific sales gas customer class and, where applicable, gas transportation customer rate class; and
  - (II) derive the amount of the GCA applied to each specific sales gas customer class and, where applicable, gas transportation customer rate classes.

- (h) GCA attachment No. 7 - Customer Notice. This attachment shall provide the form of notice to customers and the public concerning the utility's proposed GCA change. In its customer notice for each sales gas customer class, the utility shall include the following:
  - (I) current and proposed GCA rates and percentage change;
  - (II) comparison of the previous gas purchase year's last average annual bill under prior rates and the projected average annual bill under the proposed GCA rates and percentage change in the total bill amount using an average usage amount for each customer class;
  - (III) comparison of the prior year's peak winter month bill under prior rates and the projected peak winter month bill under the proposed GCA rates and percentage change using an average peak winter month usage amount for each customer class; and
  - (IV) with the annual GCA application, a statement that the utility made a separate gas purchase report filing in accordance with rule 4607 to begin the initial prudence review evaluation process for the prior gas purchase year.
- (i) GCA attachment No. 8 - components of delivered gas cost. This attachment shall detail the itemized rate components of delivered gas cost to the customer (rate), per rule 4406.
- (j) GCA attachment No. 9 - proposed tariff. This attachment shall contain the tariff sheets proposed by the utility to reflect the proposed GCA change.
- (k) GCA attachment No. 10 - rate base. This attachment shall calculate the used and useful rate base assets employed by the utility for Commission-regulated gas operations for the most recently completed 12-month period ending June 30.
- (l) GCA attachment No. 11 - net operating earnings. This attachment shall calculate the utility's net operating earnings for jurisdictional gas operations during the most recently completed 12-month period ending June 30.
- (m) GCA attachment No. 12 - capital structure and cost of capital. This attachment shall calculate the following information for the most recently completed 12-month period ending June 30, the utility's:
  - (I) capital structure for jurisdictional gas operations;
  - (II) cost of long-term debt and preferred equity;
  - (III) cost of common equity; and
  - (IV) weighted average cost of capital.

**4605. Gas Purchase Plans.**

- (a) GPP filing requirements. The utility shall file its GPP as a "Submittal for Determination of Completeness of GPP." This submittal shall include the following proceeding caption: "In the

matter of Gas Purchase Plans and Gas Purchase Reports for [utility] for the Gas Purchase Year from July 1, [year] through June 30, [year]."

- (b) Contents of GPP filing. In the GPP, the utility shall submit to the Commission the following:
  - (I) the information required by rule 4606;
  - (II) the utility's forecasted quantity of gas to be purchased over the ensuing gas purchase year for each service level;
  - (III) the utility's forecasted pricing for each receipt point/area; and
  - (IV) the utility's portfolio management plan.
- (c) Commission procedures for processing filings. Upon receipt of a GPP submittal, the Commission shall assign a proceeding number and shall review the submittal solely for completeness (i.e., compliance with the information requirements of these rules). The Commission shall not: hold a hearing on the substance of the GPP, entertain interventions by interested parties, require the filing of testimony or permit discovery. The Commission shall not render a decision approving or disapproving the substantive information contained in the submittal.
- (d) Review timelines. Commission staff shall review the submittal and, within 15 calendar days of the filing, shall provide written notification to the utility of any deficiencies in the submittal. The utility shall file the requested information, or a written statement indicating that the utility believes the additional information is not required, within 15 calendar days after the date of the Commission staff notification. Upon receipt of final information or the written statement, Commission staff shall place the submittal on the agenda for consideration at the next available Commissioners' weekly meeting. If the Commission fails to mail its determination on completeness of the submittal within 15 calendar days of receipt of final information or the written statement, the submittal shall be deemed complete.
- (e) Utilities with multiple GCA rate areas. A utility with more than one approved GCA rate area in Colorado shall file a separate GPP for each GCA rate area. These GPPs may be filed in a single submittal.
- (f) GPP no longer reflects market conditions. A utility shall file a new GPP within 30 days of its determination that the currently effective GPP no longer substantively reflects active purchasing conditions or the utility's planned purchasing practices.

**4606. Contents of the GPP.**

A GPP submittal shall contain the following attachments. The utility shall organize attachments in a manner that specifically references, and responds to, the requirements of paragraphs (a) through (d) of this rule. With its submittal, the utility shall provide cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment.

- (a) GPP attachment No. 1 - gas purchase schedule. This attachment shall provide a forecast of the specific gas commodity supplies, segregated by receipt point/area, which the utility plans to



purchase in order to meet forecasted sales gas demand during each month of the applicable gas purchase year.

- (b) GPP attachment No. 2 – gas purchasing pricing description. For each specific receipt point/area, this attachment shall provide an estimate of applicable ranges of forecast index prices expected to be incurred, short-term fixed prices (one-year or other appropriate term), and other relevant pricing options, as applicable to the portfolio management plan described in GPP attachment 3.
- (c) GPP attachment No. 3 – portfolio management plan. This attachment shall provide a plan stating how the utility plans to manage its gas supply portfolio for the gas purchase year. This attachment shall also include a description and analysis of the options the utility considered, or will consider, and the steps the utility has taken, or will take, to reduce customers' risk of gas price volatility for the gas purchase year. To the extent a utility proposes to use gas price volatility risk management tools, this attachment shall include a description of the utility's policy for implementing such risk management tools, including a projection of such costs and the assumptions underlying all cost estimates.
- (d) GPP attachment No. 4 - forecasted upstream service costs. This attachment shall include the following information for each month of the applicable gas purchase year:
  - (I) An itemized list of all upstream services, by provider and service level or rate schedule, and associated costs, that the utility expects to purchase in the upcoming gas purchase year in order to meet sales gas and gas transportation demand .
  - (II) A comparison of forecasted design peak day delivery quantity with all sources of capacity available to the utility, including forecasted upstream services, forecasted gas commodity to be purchased directly into the utility's distribution system (i.e., city gate purchases) on a firm basis, and the utility's own gas storage facilities or purchased gas storage capacity.
  - (III) A comprehensive explanation of the utility's forecasted level of planned upstream service purchases.
  - (IV) Forecasted capacity release volumes and revenues for release of upstream capacity by the utility.

**4607. Gas Purchase Reports and Prudence Reviews.**

- (a) GPR filing requirements. The utility shall file a GPR under the previous year's GPP proceeding number (filed approximately 15 months previously) as a separate filing from, and at the same time as, the annual GCA application. Specific attachments or other information may be filed under seal; however, an explanation of the confidential nature of the attachments or information must be included in the GPR filing.
- (b) Prudence review process. Based on the initial evaluation of the GPR, the Commission may initiate a prudence review hearing. The Commission shall initiate this hearing by written order within 120 days of the filing of the GPR. The prudence review may result in tariff or rate changes that could affect different classifications of customers.

- (c) Prudence review standard. For purposes of GCA recovery, the standard of review to be used in assessing the utility's action (or lack of action) in a specific gas purchase year is: whether the action (or lack of action) of a utility was reasonable in light of the information known, or which should have been known, at the time of the action (or lack of action).
- (d) Burden of proof. If the Commission elects to hold a hearing, the utility shall have the burden of proof and the burden of going forward to establish the reasonableness of actual gas commodity and demand costs paid by the utility, actual costs incurred in volatility management, and actual upstream service costs of any nature incurred during the review period.
- (e) Utility testimony and attachments. If the Commission sets a hearing, the utility shall file its testimony supporting gas cost recovery for the gas purchase year at issue. The testimony shall be filed in question-and-answer format. The utility shall file its testimony not later than 45 days after the Commission sets the matter for hearing.

**4608. Contents of the GPR.**

A GPR shall contain the following attachments. The utility shall organize the attachments in a manner that specifically references, and responds to, paragraphs (a) through (d) of this rule. The utility shall also present all such information in a format comparable with, and corresponding to, the information forecasted in the utility's GPP submittal as required pursuant to rule 4606 and GCA application pursuant to rule 4604. The utility shall provide an explanation of, and justification for, any material deviations from its GPP. All underlying support documentation and work papers shall be made available. With its filing, the utility shall provide cross-referenced and footnoted work-papers fully explaining the amounts shown in each attachment.

- (a) GPR attachment No. 1 - actual gas commodity purchases. This attachment shall provide, in a format comparable to the information provided in GPP attachment 1, the quantities of, and actual invoice costs of, specific gas commodity supplies, segregated by receipt point/area that the utility purchased in order to meet actual sales gas and gas transportation demand during the peak day and for each month of the gas purchase year.
- (b) GPR attachment No. 2 - description of actual market prices. This attachment shall provide, in a format comparable to the information provided in GPP attachment 2, actual index prices, short-term fixed prices (one-year, or other appropriate term), and other relevant pricing options for each specific receipt point area, as applicable to the portfolio management plan described in GPP and GPR attachments 3.
- (c) GPR attachment No. 3 - actual portfolio purchases. This attachments shall provide, in a format comparable to the information provided in GPP exhibit 3, a comparison of the utility's portfolio management plan and the results actually achieved through the implementation of this plan (or modification thereto), in order to demonstrate, using the standard of review specified in paragraph 4607(c), the prudence of actual portfolio purchases. This attachment shall include a detailed itemization of gas price volatility risk management costs if applicable.
- (d) GPR attachment No. 4 - actual upstream service costs. This attachment shall provide, in a format comparable to the information provided in GPP attachment 4, the following information for each month of the gas purchase year:

- (I) an itemized list of the upstream services the utility actually purchased in order to meet sales gas and gas transportation demand;
- (II) an itemized listing of the specific costs the utility incurred to purchase upstream services;
- (III) actual peak day demand experienced by the utility during the gas purchase year; and
- (IV) an itemized list of capacity release volumes and revenues.

**4609. General Provisions.**

- (a) For each attachment filed by the utility as confidential under rules 4600 through 4609, the utility shall provide, at a minimum, a version of the attachment with publicly available information.
- (b) A utility shall monitor the net under- or over-recovery balance in USOA Account No. 191 on a monthly basis. On a quarterly basis, or as otherwise established individually for a utility, a utility shall file, within 30 days of the end of the quarter, a report to the Commission stating the USOA Account No. 191 balance calculation for each rate area. The reports shall include the USOA Account No. 191 balance information specified in GCA attachment 3 and shall be filed in one common proceeding, established by the Commission to receive USOA Account No. 191 balance filings from all utilities. If the utility identifies a significant net under- or over- recovery balance during the gas purchase year, the utility shall initiate appropriate action to mitigate the significant under- or over- recovery balance.

**4610. – 4699. [Reserved].**

**APPEALS OF LOCAL GOVERNMENT LAND USE DECISIONS**

**4700. Scope and Applicability.**

Rules 4700 through 4707 apply to all utilities or power authorities which seek to appeal a local government action concerning a major natural gas facility.

**4701. Definitions.**

The following definitions apply to rules 4700 through 4707, unless a specific statute or rule provides otherwise. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- (a) "Local government" means a county, a home rule or statutory city, a town, a territorial charter city, or a city and county.
- (b) "Local government action" means (1) any decision, in whole or in part, by a local government which has the effect or result of denying a permit or application of a utility that relates to the location, construction, or improvement of a major natural gas facility or (2) a decision imposing requirements or conditions upon such permit or application that will unreasonably impair the ability of the utility to provide safe, reliable, and economical service to the public.

- (c) "Local land use decision" means the decision of a local government within its jurisdiction to plan for and regulate the use of land.
- (d) "Major natural gas facility" is defined by § 29-20-108(3)(e), C.R.S., or by any other applicable statute.
- (e) "Power authority" means an authority created pursuant to § 29-1-204, C.R.S.

**4702. Precondition to Application.**

In order for a utility or power authority to appeal a local government action to the Commission pursuant to this rule and pursuant to § 29-20-108, C.R.S., one or more of the following conditions must be met:

- (a) the utility or power authority has applied for or has obtained a certificate of public convenience and necessity from the Commission pursuant to § 40-5-101, C.R.S., to construct the major natural gas facility that is the subject of the local government action;
- (b) a certificate of public convenience and necessity is not required for the utility or power authority to construct the major natural gas facility that is the subject of the local government action; and
- (c) the Commission has previously entered an order pursuant to § 40-4-102, C.R.S., that conflicts with the local government action.

**4703. Applications.**

- (a) To commence an appeal of a local government land use decision, a utility or power authority shall file with the Commission an application pursuant to this rule.
- (b) An application filed in accordance with §§ 29-20-108, C.R.S., and this rule shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:
  - (I) all of information required in paragraphs 4002(b) and 4002(c);
  - (II) a showing that one of the preconditions set out in rule 4702 has been met;
  - (III) identification of the major natural gas facility;
  - (IV) identification of the local government action and its impact on the major natural gas facility;
  - (V) a statement of the reasons the applying utility or power authority believes that the local government action would unreasonably impair its ability to provide safe, reliable, and economical service to the public;
  - (VI) the demonstrated need for the major natural gas facility or reference to the application made to the Commission with respect to the major natural gas facility and the resulting decision of the Commission regarding such facility;

- (VII) the extent to which the proposed facility is inconsistent with existing applicable local or regional land use ordinances, resolutions, or master or comprehensive plans;
- (VIII) whether the proposed facility would exacerbate a natural hazard;
- (IX) applicable utility engineering standards, including supply adequacy, system reliability, and public safety standards;
- (X) the relative merit, as determined through use of the normal system planning evaluation techniques of the utility or power authority, of any reasonably available and economically feasible alternatives proposed by the utility, the power authority, or the local government;
- (XI) the impact that the local government action would have on the customers of the utility or power authority who reside within and without the boundaries of the jurisdiction of the local government;
- (XII) the basis for the local government action. If available, the utility or power authority shall attach a copy of the local government action;
- (XIII) the impact the proposed facility would have on residents within the local government's jurisdiction including, in the case of a right-of-way in which facilities have been placed underground, whether those residents have already paid to place such facilities underground. If the residents have already paid to place facilities underground, the Commission will give strong consideration to that fact;
- (XIV) information concerning how the proposed major natural gas facility will affect the safety of residents within and without the boundaries of the jurisdiction of the local government; and
- (XV) an attestation that the utility or power authority will, upon filing the application with the Commission, simultaneously send the application to the local government body which took the local government action which is the subject of the appeal.

**4704. Public Hearing.**

In addition to the formal evidentiary hearing on the appeal, and pursuant to § 29-20-108(5)(b), C.R.S., the Commission shall take statements from the public concerning the appealed local government action at a public hearing held at a location specified by the local government.

**4705. Prehearing Conference, Parties, and Public Notice.**

- (a) In order to assist the parties in scheduling the public hearing, determining the scheduling of the evidentiary hearing, developing the list of persons to receive notice of these hearings, and addressing other pertinent issues, the Commission will hold a prehearing conference.
- (b) The Commission shall conduct a prehearing conference within 15 days after the application is deemed complete by the Commission.

- (c) The Commission shall join as an indispensable party the local government which took the contested local government action.
- (d) Ten days before the commencement of the prehearing conference, the local government shall submit to the parties and the Commission its preference for the location of the public hearing to be held in accordance with § 29-20-108(5)(b), C.R.S., and rule 4704.
- (e) The Commission will decide the date and time of the public hearing after receiving comments from the parties at the prehearing conference.
- (f) By the date of the prehearing conference, each party shall provide to the utility a list of individuals and groups to receive notice of the public hearing.
- (g) The utility or power authority shall give notice of the public hearing to the identified individuals and groups in a manner specified by the Commission. Notice may be accomplished by newspaper publication, bill insert, first class mail, or any other manner deemed appropriate by the Commission.
- (h) If the local government is unable to provide meeting space for the public hearing, and space needs to be acquired, then the utility or power authority shall bear any cost associated with the rental of such space for the public hearing.
- (i) The parties are encouraged to confer prior to the prehearing conference to develop a schedule for the filing of testimony and the dates for the formal evidentiary hearing.

**4706. Denial of Appeal.**

In accordance with § 29-20-108(5)(e), C.R.S., the Commission shall deny an appeal of a local government action if the utility or power authority has failed to comply with the following notification and consultation requirements:

- (a) A utility or power authority shall notify the affected local government of its plans to site a major natural gas facility within the jurisdiction of the local government prior to submitting the preliminary or final permit application, but in no event later than filing a request for a certificate of public convenience and necessity pursuant to Article 5 of Title 40, C.R.S., or the filing of any annual filing with the Commission that proposes or recognizes the need for construction of a new major natural gas facility or the extension of an existing facility. If a utility or power authority is not required to obtain a certificate of public convenience and necessity pursuant to Article 5 of Title 40, C.R.S., or to file annually with the Commission to notify the Commission of proposed construction of a new major natural gas facility or the extension of an existing facility, then the utility or power authority shall notify any affected local governments of its intention to site a new major natural gas facility within the jurisdiction of the local government when such utility or power authority determines that it intends to proceed to permit and to construct the facility. Following such notification, the utility or power authority shall consult with the affected local governments in order to identify the specific routes or geographic locations under consideration for the site of the major natural gas facility and to attempt to resolve land use issues that may arise from the contemplated permit application.

- (b) In addition to its preferred alternative within its permit application, the utility or power authority shall consider and present reasonable siting and design alternatives to the local government or shall explain why no reasonable alternatives are available.

**4707. Procedural Rules.**

Pursuant to § 29-20-108(5)(b), C.R.S., any appeal brought by a utility or power authority under this section shall be conducted in accordance with the procedural requirements of Article 6, Title 40, C.R.S., including § 40-6-109.5, C.R.S. Evidentiary hearings on any such appeals shall be conducted in accordance with § 40-6-109, C.R.S.

**4708. – 4749. [Reserved].**

**DEMAND SIDE MANAGEMENT**

**4750. Overview and Purpose.**

These rules implement §§ 40-1-102, 40-3.2-101, 40-3.2-103, and 40-3.2-105, C.R.S. for LDCs required by statute to be rate-regulated. Consistent with statutory requirements, the purpose of these Demand Side Management (DSM) rules is to reduce end-use natural gas consumption in a cost effective manner, in order to save money for consumers and utilities, and protect the environment by encouraging the reduction of emissions and air pollutants. These rules direct natural gas utilities in the design and implementation of programs that will enable sales customers to participate in DSM. The LDC shall design DSM programs for its full service customers to achieve cost-effective energy savings, considering factors such as: achievable energy savings, customer benefits, cost effectiveness ratios, adoption potential, market transformation capability and ability to replicate in the utility service territory.

- (a) Each utility shall file an application for approval of a DSM plan within the parameters set forth in these rules. In the application, the utility shall include a proposed expenditure target, savings target, funding mechanism, and cost-recovery mechanism.
- (b) Each utility shall annually file an advice letter or application for cost recovery, as permitted herein.
- (c) Each utility shall annually file a DSM report. The DSM report shall include the results of any measurement and verification (M&V) evaluation conducted during the DSM report period.

**4751. Definitions.**

The following definitions apply to rules 4750 through 4760, unless § 40-1-102 provides otherwise.

- (a) “Amortization” means the systematic spreading of expenditures or capital costs incurred for DSM programs, through regular accounting entries over a specified period of time.
- (b) “Benefit/cost ratio” means the ratio of the net present value of benefits to the net present value of costs, as calculated using the modified TRC test.
- (c) “Cost effective” means a benefit/cost ratio of greater than one.

- (d) “Demand side management” (DSM) means the implementation of programs or measures which serve to shift or reduce the consumption of, or demand for, natural gas.
- (e) “Discount rate” means the interest rate used in determining the present value of future cash flows of DSM costs and benefits, for both forecasted and actual cash flows. The forecasted DSM costs and benefits are used to estimate the cost effectiveness of DSM measures to develop a cost effective DSM portfolio. The actual DSM costs and benefits, which are the actual costs of the program and the documented energy savings, are used to determine net economic benefits for the purpose of calculating the bonus. Discount rate shall be the utility’s after-tax weighted average cost of capital (WACC).
- (f) “DSM education” means a program, including but not limited to an energy audit, that contributes indirectly to a cost-effective DSM program by promoting customer awareness and participation.
- (g) “DSM measure” means an individual component or technology, such as attic insulation or replacement of equipment.
- (h) “DSM period” means the effective period of an approved DSM plan.
- (i) “DSM plan” means the DSM programs, goals, and budgets over a specified DSM period, generally considered in one year increments, as may be proposed by the utility.
- (j) “DSM program” means any combination of DSM measures, information and services offered to customers to reduce natural gas usage.
- (k) “Energy efficiency program” see DSM program.
- (l) “Gas Demand-Side Management Cost Adjustment” (G-DSMCA) means a rate adjustment mechanism designed to compensate a utility for its DSM program costs.
- (m) “Gas Demand-Side Management bonus” (G-DSM bonus) means a bonus awarded to a utility in accordance with § 40-3.2-103(2)(d), C.R.S.
- (n) “Market transformation” means a strategy for influencing the adoption by consumers of new techniques or technologies. The objective is to overcome barriers within a market through coordinating tactics such as education, training, product demonstration and marketing, often conducted in concert with rebates or other financial incentives.
- (o) “Modified Total Resource Cost test” or “modified TRC test” means an economic cost-effectiveness test used to compare the net present value of the benefits of a DSM program or measure over its useful life, to the net present value of costs of a DSM measure or program for the participant and the utility, consistent with § 40-1-102(5), C.R.S. In performing the modified TRC test, the benefits shall include, but are not limited to, as applicable: the utility’s avoided production, distribution and energy costs; the participant’s avoided operating and maintenance costs; the valuation of avoided emissions; and non-energy benefits as set forth in rule 4753. Costs shall include utility and participant costs. The utility costs shall include the net present value of costs incurred in accordance with the budget set forth in rule 4753.



- (p) “Net economic benefits” means the net present value of all benefits in the modified TRC test, as applied to the utility’s portfolio of DSM programs, less the net present value of the costs in the modified TRC test associated with that same portfolio.
- (q) “Sales customer” or “full service customer” means a residential or commercial customer that purchases a bundled natural gas supply and delivery service from a utility but does not include customers served under a utility’s gas transportation service rate schedules.

**4752. Filing Schedule.**

- (a) Each utility shall implement and maintain its DSM plan and G-DSMCA, as approved by the Commission.
- (b) Each utility shall submit its annual DSM report on or before April 1 of each year.
- (c) Each utility seeking a G-DSM bonus shall file an application pursuant to rule 4760 requesting approval of such bonus on or before April 1 of each year.
- (d) Each utility shall file an advice letter on or before May 31 of each year to adjust the G-DSMCA to be effective July 1 for a period of 12 months. Alternatively, each utility may file a combined application on or before April 1 of each year seeking a G-DSM bonus, as well as an adjustment to the G-DSMCA, to be effective July 1 for a period of 12 months.
- (e) By May 1 of the final year of the currently effective DSM plan, each utility shall file by application a prospective natural gas DSM plan for Commission approval.

**4753. Periodic DSM Plan Filing.**

Each utility shall periodically file, in accordance with paragraph 4752(e), a prospective natural gas DSM plan that covers a DSM period of three years, unless otherwise ordered by the Commission. The plan shall include the following information:

- (a) the utility’s proposed expenditures by year for each DSM program, by budget category; the sum of these expenditures represents the utility’s proposed expenditure target as required by § 40-3.2-103(2)(a), C.R.S.;
- (b) the utility’s estimated natural gas energy savings over the lifetimes of the measures implemented in a given annual DSM program period, expressed in dekatherms per dollar of expenditure, and presented for each DSM program proposed for Commission approval; this represents the utility’s proposed savings target required by § 40-3.2-103(2)(b), C.R.S.;
- (c) the anticipated units of energy to be saved annually by a given annual DSM program, which equals the product of the proposed expenditure target and proposed savings target; this product is referred to herein as the energy target;
- (d) the estimated dollar per therm value that represents the utility’s annual fixed costs that are recovered through commodity sales on a per therm basis;

- (e) the utility shall include in its DSM plan application data and information sufficient to describe the design, implementation, oversight and cost effectiveness of the DSM programs. Such data and information shall include, at a minimum, program budgets delineated by year, estimated participation rates and program savings (in therms);
- (f) in the information and data provided in a proposed DSM plan, the utility shall reflect consideration of the factors set forth in the Overview and Purpose, rule 4750. At a minimum the utility shall provide the following information detailing how it developed its proposed DSM program:
  - (I) descriptions of identifiable market segments, with respect to gas usage and unique characteristics;
  - (II) a comprehensive list of DSM measures that the utility is proposing for inclusion in its DSM plan;
  - (III) a detailed analysis of proposed DSM programs for a utility's service territory in terms of markets, customer classes, anticipated participation rates (as a number and a percent of the market), estimated energy savings and cost effectiveness;
  - (IV) a ranking of proposed DSM programs, from greatest value and potential to least, based upon the data required in subparagraph (f)(III);
  - (V) proposed marketing strategies to promote participation based on industry best practices;
  - (VI) calculation of cost effectiveness of the proposed DSM programs using a modified TRC test. Each proposed DSM program is to have a projected value greater than or equal to 1.0 using a modified TRC test, except as provided for in paragraph 4753 (g);and
  - (VII) an analysis of the impact of the proposed DSM program expenditures on utility rates, assuming a 12-month cost recovery period.
- (g) In its DSM plan, the utility shall address how it proposes to target DSM services to low-income customers. The utility shall also address whether it proposes to provide DSM services directly or indirectly through financial support of conservation programs for low-income households administered by the State of Colorado, as authorized by § 40-3.2-103(3)(a), C.R.S. The utility may propose one or more low-income DSM programs that yield a modified TRC test value below 1.0.
- (h) In proposing an expenditure target for Commission approval, pursuant to § 40-3.2-103 (2)(a), C.R.S., the utility shall comply with the following:
  - (I) the utility's annual expenditure target for DSM programs shall be, at a minimum, two percent of a natural gas utility's base rate revenues, (exclusive of commodity costs), from its sales customers in the 12-month calendar period prior to setting the targets, or one-half of one percent of total revenues from its sales customers in the 12-month calendar period prior to setting the targets, whichever is greater;
  - (II) the utility may propose an expenditure target in excess of two percent of base rate revenues; and

- (III) funds spent for education programs, market transformation programs and impact and process evaluations and program planning related to natural gas DSM programs may be recovered without having to show that such expenditures, on an independent basis, are cost-effective; such costs shall be included in the overall benefit/cost ratio analysis.
- (i) The utility shall propose a budget to achieve the expenditure target proposed in paragraph 4753 (a). The budget shall be detailed for the overall DSM plan and for each program for each year and shall be categorized into:
  - (I) planning and design costs;
  - (II) administrative and DSM program delivery costs;
  - (III) advertising and promotional costs, including DSM education;
  - (IV) customer incentive costs;
  - (V) equipment and installation costs;
  - (VI) measurement and verification costs; and
  - (VII) miscellaneous costs.
- (j) The budget shall explain anticipated increases/decreases in financial resources and human resources from year to year.
- (k) A utility may spend more than the annual expenditure target established by the Commission up to 25 percent over the target, without being required to submit a proposed DSM plan amendment. A utility may submit a proposed DSM plan amendment for approval when expenditures are in excess of 25 percent over the expenditure target.
- (l) As a part of its DSM plan, each utility shall propose a DSM plan with a benefit/cost value of unity (1) or greater, using a modified TRC test.
- (m) For the purposes of calculating a modified TRC, the non-energy benefits of avoided emissions and societal impacts shall be incorporated as follows.
  - (I) The initial TRC ratio, which excludes consideration of avoided emissions and other societal benefits, shall be multiplied by 1.05 to reflect the value of the avoided emissions and other societal benefits. The result shall be the modified TRC. A utility may propose for approval a different factor for avoided emissions and societal impacts, but must submit documentation substantiating the proposed value.
- (n) Measurement and verification (M & V) plan. The utility shall describe in complete detail how it proposes to monitor and evaluate the implementation of its proposed programs. The utility shall explain how it will accumulate and validate the information needed to measure the plan's performance against the standards, pursuant to rule 4755. The utility shall propose measurement and verification reporting sufficient to communicate results to the commission in a detailed, accurate and timely basis.

**4754. Annual DSM Report and Application for Bonus and Bonus Calculation.**

On the schedule set forth in rule 4752, the utility shall provide the Commission a detailed DSM report and application for bonus.

- (a) In the annual DSM report, the utility shall describe its actual DSM programs as implemented. For each DSM program, the utility shall document actual program expenditures, energy savings, participation levels and cost-effectiveness.
- (b) Annual program expenditures shall be separated into cost categories contained in the approved DSM plan.
- (c) For each DSM program, the utility shall compare the program's proposed and actual expenditures, savings, participation rate, and cost-effectiveness; in addition, the utility shall prepare an assessment of the success of the program, and list any suggestions for improvement and greater customer involvement.
- (d) The utility shall provide actual benefit/cost results for the overall DSM plan and individual DSM programs implemented during the plan year. The benefit/cost analysis shall be based on the costs incurred and benefits achieved, as identified in the modified TRC test. Benefit values are to be based upon the results of M & V evaluation, when such has been conducted as set forth in rule 4755. Otherwise, the benefit values of the currently approved DSM plan are to be used.
- (e) If the annual report covers a year within which an M & V evaluation was completed, the complete M & V results are to be included as part of the annual report.
- (f) The utility may file an application for bonus, pursuant to rule 4760. The application for bonus shall include the utility's calculation of estimated bonus applying the methodology set forth in this rule to the utility's actual performance.
- (g) The Commission shall determine the level of bonus, if any, that the utility is eligible to collect on the basis of the information included in the report, pursuant to the bonus criteria and process set forth, below.
  - (l) The primary objective of the bonus is to encourage cost-effective energy savings. The amount of bonus earned, if any, will correlate with the utility's performance relative to the approved savings target (dekatherms saved per dollar expended) and the energy target. Assuming all other factors that affect consumption remain unchanged, effective DSM programs will reduce per customer commodity consumption, which may lead to revenue reductions for the utility. The utility may include in the bonus application a request for approval to recover a calculated amount of revenue that acknowledges the DSM program reduced the utility's revenue. The recovery amount for reduced revenue is separate from any bonus determined by the Commission and shall be calculated, as follows:
    - (A) the utility shall calculate a dollar per therm value that represents the utility's annualized fixed costs that are recovered through commodity sales on a per therm basis;

- (B) the utility shall include in the DSM filing pursuant to rule 4753 a proposed dollar per therm value with the calculation methodology and supporting documentation;
  - (C) the recovery amount for reduced revenue shall be calculated by multiplying the dollar per therm value by the annualized number of therms saved and reported in the utility's annual DSM report for the plan year;
  - (D) the recovery of the reduced revenue amount shall be through the Demand-Side Management Cost Adjustment (DSMCA), over the same twelve month period in which any approved bonus amount is recovered, as set forth in subparagraph 4752 (b)(l); and
  - (E) for the purpose of inclusion in the above calculation, the annual report shall include the number of therms projected to be saved from the DSM programs in the twelve months following the end of the program year.
- (II) As a threshold matter, the utility must expend at least the minimum amount set forth in subparagraph 4753 (h)(l), in order to earn a bonus.
- (III) The bonus amount is a percentage of the net economic benefits resulting from the DSM plan over the period under review. The percentage value is the product of the two factors:
- (A) The Energy Factor is determined by the percentage of the energy target achieved by the utility. The energy factor is zero plus 0.5 percent for each one percent above 80 percent of the energy target achieved by the utility.
  - (B) The Savings Factor is the actual savings achieved divided by the approved savings target. The actual savings achieved and approved savings target are each expressed in dekatherms saved per dollar expended.
- (IV) The following is provided as an example of the bonus calculation, using these illustrative numbers: utility achieves 106 percent of its energy target; the utility's savings target is 15,000 dekatherms per \$1 million expended, and the utility's actual savings is 18,000 dekatherms per \$1 million.
- The energy factor would be:  $50 \text{ percent} \times (106 - 80)$ , or 13 percent
- The savings factor would be:  $18,000/15,000$  or 1.2
- The resulting bonus percentage would be:  $13 \text{ percent} \times 1.2$ , or 15.6 percent. Thus, 15.6 percent of net economic benefits would be the bonus amount.
- (h) For the purposes of calculating the bonus, the costs and benefits associated with DSM programs targeted to low-income customers may be excluded as follows:
- (l) the costs and benefits associated with a low-income DSM program may be excluded from the calculation of the net economic benefits for the entire DSM portfolio if the modified TRC value for the low-income program is below 1.0; and

- (II) the expenditures and therms saved associated with a low-income DSM program may be excluded from the calculation of the Savings Factor if the therms saved per dollar expended for the low-income program is below the approved savings target for the overall DSM portfolio.
- (i) The maximum bonus is 20 percent of net economic benefits or 25 percent of expenditures, whichever is less.
- (j) Any awarded bonus shall be authorized as a supplement to a utility and not count against its authorized rate of return or be considered in rate proceedings. The awarded bonus shall be recovered through the G-DSMCA over a 12-month period after approval of the bonus.

**4755. Measurement and Verification.**

- (a) Each utility shall implement a measurement and verification (M & V) program to evaluate the actual performance of its DSM program. The utility shall present its M & V plan as a part of its DSM plan application, pursuant to rule 4753, and shall include the complete M & V evaluation results with its annual DSM report in those years when the M & V is conducted.
- (b) As a part of its M & V program, the utility shall, at a minimum, design a M & V plan to evaluate the effectiveness of the actual DSM measures and programs implemented by the utility. The M & V plan shall address: sampling bias; a data gathering process sufficient to yield statistically significant results; and generally accepted methods of data analysis. The M & V plan shall also include an evaluation of free ridership, spillover and the net-to-gross ratio. The M & V evaluation shall be implemented at least once per the DSM plan period. Subsequent DSM plan applications shall reflect the results of all completed M & V evaluations.
- (c) The M & V evaluation shall, at a minimum, include the following:
  - (I) an assessment of whether the DSM programs have been implemented as set forth in its Commission approved DSM plan;
  - (II) a measurement of the actual energy savings for each DSM program, in dekatherms per dollar expended and in total dollars, and a comparison to the corresponding utility projections in the approved DSM plan;
  - (III) to the extent feasible, an assessment of the period of time that each DSM measure actually remains in service, and a comparison to the corresponding utility projections in the approved DSM plan;
  - (IV) a summary of the actual benefit/cost ratio for each DSM program within the approved DSM plan;
  - (V) an assessment of the extent to which education and market transformation efforts are achieving the desired results; and
  - (VI) recommendations for how the utility can improve the market penetration and cost effectiveness of individual DSM programs.

**4756. General Provisions Concerning Cost Allocation and Recovery.**

- (a) Amortization periods.
  - (I) For the base rate method, the utility shall propose the amortization period. The utility shall specify and explain the rationale for the amortization period proposed for each DSM program as a part of its DSM plan application, filed pursuant to rule 4753.
  - (II) For the expense method, the utility shall recover the annual expenditures projected for that year over a one-year period.
- (b) Fuel switching. Fuel switching from natural gas to other fossil fuel derived energy sources shall not be included in the gas utility's DSM program. Programs to save natural gas through switching to renewable energy sources such as solar heating and ground source heat pumps are allowed.
- (c) A utility that provides both regulated gas and electric service shall give consideration to the administrative benefits and reduced costs associated with combining gas and electric DSM activities and shall assign costs and benefits appropriately to each plan.
- (d) Distribution of DSM program expenses.
  - (I) The utility shall include in its portfolio-level benefit/cost analysis all indirect costs relating to DSM, including but not limited to DSM customer education, program design, and evaluation costs.
  - (II) A utility's existing gas efficiency and conservation customer education tools, such as on-line energy assessment tools or other similar internet based tools, may be included in a utility's gas DSM plan and costs recovered pursuant to the gas DSMCA rule.

**4757. Funding and Cost Recovery Mechanism.**

The purpose of the G-DSMCA is to enable utilities to recover prudently incurred gas DSM program expenses without requiring a change in their base rates for gas sales. All such costs, plus any G-DSM bonus approved by the Commission, shall be recovered through the G-DSMCA that is set on an annual basis, and collected from July 1 through June 30. The G-DSMCA allows for prospective recovery of prudently incurred costs of DSM programs within the DSM program expenditure target approved by the Commission in order to provide for funding of the utility's DSM programs, as well as recovery of deferred G-DSMCA costs, without having to file a rate case.

- (a) A utility may spend a disproportionate share of total expenditures on one or more classes of customers, provided, however, that cost recovery for programs directed at residential customers are to be collected from residential customers only and that cost recovery for programs directed at nonresidential customers are to be collected from nonresidential customers only, except as provided for in paragraph 4757 (f).
- (b) The utility may recover its DSM program expenditures either through expensing or by adding DSM program expenditures to base rates as a part of, or outside of, a rate case, with an amortization period as set forth in rule 4756.

- (c) There shall be no financial penalty assessed on a utility for failing to reach its approved DSM program expenditure target, nor shall there be a bonus simply for meeting its DSM program expenditure target. All prudently incurred expenditures for the utility's portfolio of DSM programs are recoverable. However, the portion of costs yielding a modified TRC test value below 1.0 loses its presumption of prudence and is subject to review.
- (d) Amounts not spent under the DSM program expenditure target shall not roll-over to the next DSM period.
- (e) A utility has the discretion and the responsibility of managing the portfolio of DSM programs to meet the benefit to cost ratio and the energy and savings targets. In implementing DSM programs, a utility shall use reasonable efforts to maximize energy savings consistent with the approved DSM plan.
- (f) A utility may continue DSM programs that were in existence on or before May 22, 2007, the effective date of § 40-3.2-103, C.R.S., concerning measures to promote energy efficiency, and shall not be required to obtain approval from the Commission for recovery of costs associated with such programs. Any new expenditure for such programs must be included in the annual DSM plan filing and G-DSMCA application. Existing low-income DSM programs that recover costs from all customer classes shall continue such recovery.
- (g) A utility shall file a request to adjust its G-DSMCA factor either through an application or an advice letter and tariffs, pursuant to the relevant provisions of title 40, articles 1 through 7 of the Colorado Public Utilities Law and of the Commission rules. The G-DSMCA shall be filed pursuant to the schedule provided in rule 4752.
- (h) The G-DSMCA filing shall include information and attachments as required in rule 4758. If the M & V evaluation required by rule 4755 yields benefit/costs test results that impact the allowable recovery of costs or currently approved bonus, then the utility shall include such adjustments in the G-DSMCA filing and tariffs.
- (i) If the projected DSM program costs have changed from those used to calculate the currently effective G-DSMCA cost or if a utility's deferred G-DSMCA cost balance increases or decreases sufficiently, the utility may file an application to revise its currently effective G-DSMCA factor to reflect such changes, provided that the resulting change to the G-DSMCA factor equates to a base rate change of at least one cent (\$0.01) per Mcf or Dth. A utility has the burden of proof to justify any interim G-DSMCA filings and the Commission has the discretion to consolidate the interim G-DSMCA filing with the next regularly scheduled annual G-DSMCA filing.
- (j) Applicability of the G-DSMCA factor. The G-DSMCA factor shall be separately calculated and applied to the utility sales gas base rate schedules of residential and non-residential customers.
- (k) Return on DSM program expenditures to be amortized. For utilities that choose to amortize the DSM program expenditure, the balance of a utility's investments in cost-effective DSM programs shall earn a return equal to the utility's current after-tax weighted average cost of capital.



- (l) Interest on under- or over-recovery. The amount of net interest accrued on the average monthly balance in sub-accounts of Account No. 186 (whether positive or negative), is determined by multiplying the monthly balance by an interest rate equal to the Commission-authorized after-tax weighted average cost of capital.
- (m) Calculation of the G-DSMCA factor. The G-DSMCA factor shall be calculated separately for residential and non-residential customers to at least the accuracy of two significant places.

**4758. Contents of Gas DSM Cost Adjustment Filing.**

- (a) General Provisions.
  - (I) A filing for a gas DSM cost adjustment (G-DSMCA) shall contain justifying information sufficient in detail to permit the Commission to determine the accuracy of the supporting calculation.
  - (II) The G-DSMCA filing shall include a complete set of work papers and all other documents relied on in preparing the adjustment.
  - (III) The provisions of this rule do not supersede other Commission rules that contain additional applicable filing requirements.
- (b) Specific Provisions. The filing shall contain detailed schedules and supporting documents that establish, at a minimum, the following:
  - (I) the detailed calculation of the G-DSMCA for each customer class based on the following general formula:
    - (A)  $\text{current G-DSMCA factor} = \frac{\text{current G-DSMCA cost} + \text{deferred G-DSMCA cost}}{(\text{forecasted sales customer} \times \text{monthly service charge} + \text{forecasted sales gas quantity} \times \text{base rate})}$ ; and
    - (B) the G-DSMCA factor will also include the current G-DSM bonus plus any adjustment necessary to previously approved G-DSM bonuses;
  - (II) a detailed schedule showing the computation of interest, as applicable, to deferred amounts;
  - (III) the absolute and percentage impact of the proposed rate on the base rates and on the total monthly bills of typical customers in each customer class;
  - (IV) a schedule detailing the allocation of costs to each customer class;
  - (V) proposed customer notice detailing rate impact and effective date;
  - (VI) proposed tariff implementing the proposed G-DSMCA; and

- (VII) if any gas DSM costs are proposed to be recovered by rate base treatment, with a return on the unamortized balance, a statement of current net operating earnings, a detailed calculation of the related revenue requirement and an attachment detailing any differences in the proposed rate base treatment compared to the regulatory practices employed by the Commission in its last general rate case for the applicant.

**4759. Bill Itemization.**

Consistent with rule 4406, a utility shall provide itemized gas cost information with gas DSM costs to all customers commencing with the first complete billing cycle in which the new rates are in effect.

**4760. Gas DSM Bonus (G-DSM Bonus) Applications.**

The Commission shall review each G-DSM bonus application submitted and shall determine the level of bonus, if any, for which the utility is eligible. The collection on any G-DSM bonus awarded will be apportioned between residential and nonresidential customers based on the proportion of residential and nonresidential net economic benefits used to calculate the G-DSM bonus.

- (a) G-DSM bonus filing requirements. The utility shall file its G-DSM bonus application as part of the annual report submitted to the Commission on the timetable set forth in rule 4752. The utility may request a G-DSM bonus not to exceed the lower of 25 percent of the expenditures or 20 percent of the net economic benefits of the DSM programs, applying the bonus calculation procedure set forth in rule 4754. The G-DSM bonus, as modified and approved by the Commission, shall not count against a gas utility's authorized rate of return or be considered as net operating earnings in rate proceedings.
- (b) Contents of G-DSM bonus filing. In the G-DSM bonus filing, the utility shall submit to the Commission the following, at a minimum:
  - (I) documented expenditures on DSM programs for the current G-DSMCA period;
  - (II) gas savings for the calendar year for which the bonus is to be awarded estimated following and the techniques approved in the DSM plan. The utility shall explain whether the actual gas savings are validated through the measurement and verification process as approved in the utility's DSM plan;
  - (III) estimated cost-effectiveness of program expenditures for the current G-DSMCA period in terms of the amount of gas saved per unit of program expenditures;
  - (IV) actual gas savings and the techniques used to calculate these gas savings for the prior G-DSMCA period. The utility shall explain whether the actual gas savings are validated through the measurement and verification process, pursuant to rule 4755;
  - (V) actual cost-effectiveness of program expenditures for the prior G-DSMCA period in terms of the amount of gas saved per unit of program expenditures. The utility shall explain whether the actual cost effectiveness of program expenditures is validated through the measurement and verification process, pursuant to rule 4755; and
  - (VI) proposed tariffs containing rates to collect the bonus over 12 months.

- (c) The Commission shall issue a decision approving, modifying, or disapproving a DSM bonus application within 90 days of the utility filing of the application. The Commission shall allow oral testimony and shortened discovery response times as necessary to expedite the schedule.
- (d) Accounting for G-DSM bonus. Accounting for G-DSM bonus shall follow what has been prescribed for G-DSMCA costs, specifically in regard to interest on over- and under- recovery. A separate sub-account in Account No. 186 shall be created for any deferred G-DSM bonus amount.
- (e) Prudence review and adjustment of G-DSM bonus. If the Commission finds that the actual performance varies from performance values used to calculate the G-DSM bonus in rule 4754, then an adjustment shall be made to the amount of G-DSM bonus award. Any true-up in G-DSM bonus will be implemented on a prospective basis.

**4761. – 4799. [Reserved]**

**MASTER METER OPERATORS**

**4800. Scope and Applicability.**

These rules are applicable to any person who purchases gas service from a serving utility for the purpose of delivery of that service to end-users whose aggregate usage is measured by a master meter or other composite measurement device.

**4801. Definitions.**

The following definitions apply to rules 4800 through 4805, unless a specific statute or rule provides otherwise. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- (a) "Check-meter" means a meter or other composite measurement device used by a master meter operator to determine gas consumption by end-users served by the master meter operator.
- (b) "Master meter" means a meter or other composite measurement device which a serving utility uses to bill a master meter operator.
- (c) "Master meter operator" (MMO) means a person who purchases gas service from a serving utility for the purpose of delivering that service to end-users whose aggregate usage is measured by a master meter.
- (d) "Refund" means a refund, rebate, rate reduction, or similar adjustment.
- (e) "Serving utility" means the utility from which the master meter operator receives the gas service which the master meter operator then delivers to end-users.

**4802. Exemption from Rate Regulation.**

- (a) Pursuant to § 40-1-103.5, C.R.S., and by this rule, the Commission exempts from rate regulation under Articles 1 to 7 of Title 40, C.R.S., a master meter operator which is in compliance with rules 4803 and 4804.
- (b) A master meter operator which is not in compliance with rules 4803 and 4804 is subject to rate regulation under Articles 1 to 7 of Title 40, C.R.S., and shall comply with the applicable rules.

**4803. Exemption Requirements.**

- (a) In order to retain its exemption from rate regulation, a MMO shall do the following.
  - (I) As part of its billing for utility service, the MMO shall charge its end-users only the actual cost billed to the MMO by the serving utility. The MMO shall not charge end-users for any other costs (such as, without limitation, the costs of construction, maintenance, financing, administration, metering, or billing for the equipment and facilities owned by the MMO) in addition to the actual costs billed to the MMO by the serving utility.
  - (II) If the MMO bills its end-users separately for service, the sum of such billings shall not exceed the amount billed to the MMO by the serving utility.
  - (III) If the MMO bills its end-users separately for service, the MMO shall pass on to its end-users all refunds the MMO receives from the serving utility or otherwise.
  - (IV) The MMO shall establish procedures for giving notice of a refund to those who are not current end-users but who were end-users during the period for which the refund is paid.
  - (V) A master meter operator shall retain, for a period of not less than three years, all records of original utility billings made to the master meter operator and all records of billings and refunds made by the master meter operator to its end-users, including certification of mailing, when applicable.
- (b) In order to retain its exemption from rate regulation, a MMO shall not resell the services provided by a serving utility to the MMO for profit. Resale of services provided by a serving utility to a MMO for profit is a basis for revocation of an exemption from rate regulation.
- (c) A MMO may check-meter tenants, lessees, or other persons to whom the gas ultimately is distributed but may do so only if the following conditions are met:
  - (I) the check-meter is used solely for the purpose of determining a basis for the MMO to allocate the costs of the serving utility; and
  - (II) the MMO does not receive more than the actual amount billed to the MMO by the serving utility from the MMO's customers.

**4804. Refunds.**

- (a) When a serving utility notifies a MMO of a refund or when a refund is otherwise made related to the services provided by the serving utility to the MMO, a MMO shall refund an allocated share of the refunds to its customers within 90 days after receipt of the notice or refund from the serving utility. The notification shall be made either by first-class mail with a certificate of mailing or by inclusion in any monthly or more frequent regular written communication. The MMO shall retain the certification of mailing pursuant to subparagraph 4803(a)(V). The MMO shall also notify former customers who were end-users during the period for which the refund is made that refunds are available, to the extent such former customers can be located.
- (b) A MMO may retain any portion of a refund which is related to service taken by the MMO at its own facilities after refunds are made to its current and former customers.
- (c) If the aggregate amount of a refund which remains unclaimed after 90 days exceeds \$100, the MMO shall contribute that unclaimed amount to the energy assistance organization in accordance with rules 4410(d), (f), and (g). If the aggregate amount which remains unclaimed after 90 days does not exceed \$100, the MMO may retain the aggregate amount.

**4805. Complaints, Penalties, and Revocation of Exemption.**

- (a) Pursuant to rules 1301 and 1302, a person (including without limitation anyone taking service from a master meter operator) may make an informal complaint to the Commission or may file a formal complaint with the Commission with the respect to an alleged violation of rules 4803 and 4804.
- (b) As a result of a complaint or on its own motion, the Commission will investigate complaints concerning MMOs. If the Commission determines after investigation that an MMO has violated any of the requirements of rules 4803 and 4804, the MMO may have its exempt status revoked or may be subject to penalties as set forth in § 40-7-107, C.R.S., or both.

**4806. – 4975. [Reserved].**

**4976. Regulated Gas Utility Rule Violations, Civil Enforcement, and Civil Penalties.**

An admission to or Commission adjudication for liability for an intentional violation of the following may result in the assessment of a civil penalty of up to \$2,000.00 per offense. Fines shall accumulate up to, but shall not exceed, the applicable statutory limits set in § 40-7-113.5, C.R.S.

Citation	Description	Maximum Penalty Per Violation
	Articles 1-7 of Title 40, C.R.S.	\$2000
	Commission Order	\$2000
Rule 4005	Records and Record Retention	\$2000

Rule 4027(a)	Collection and Use of Customer Data	\$1000
Rule 4027(b),	Disclosure of Customer Data	\$2000
Rule 4027(c)	Tariff	\$1000
Rule 4027(d)	Disclosure of Customer Data	\$1000
Rule 4028(a)	Customer Notice	\$1000
Rule 4029(a),(b)	Consent Form	\$1000
Rule 4030(a)	Disclosure of Customer Data	\$2000
Rule 4030(b)	Records	\$1000
Rule 4031(a)	Disclosure of Customer Data	\$2000
Rule 4031(b)	Records	\$1000
Rule 4032(a)	Disclosure of Customer Data	\$2000
Rules 4032(c) and (d)	Consent and Records	\$1000
Rule 4033(a)	Disclosure of Aggregated Data	\$2000
Rule 4033(d)	Tariff	\$1000
Rule 4100(a)	Obtaining a Certificate of Public Convenience and Necessity for a Franchise	\$2000
Rule 4101(a)	Obtaining a Certificate of Public Convenience and Necessity or Letter of Registration to operate in a service territory	\$2000
Rule 4102(a)	Obtaining a Certificate of Public Convenience and Necessity for facilities	\$2000
Rule 4103(a), (c), (d)	Amending a Certificate of Public Necessity for changes in service territory or facilities	\$2000
Rule 4108(a), (c)	Keeping a Current Tariff on File with the Commission	\$2000
Rule 4109	Filing a New or Changed Tariff with the Commission	\$2000

Rule 4110(b),(c)	Filing an Advice Letter to Implement a Tariff Change	\$2000
Rule 4200	Construction, Installation, Maintenance and Operation of Facilities in Compliance with Accepted Engineering and Industry Standards	\$2000
Rule 4208	Anticompetitive Conduct and Unacceptable Practices	\$2000
Rule 4210	Line Extensions	\$2000
Rule 4303	Meter Testing	\$2000
Rule 4306	Record Retention of Tests and Meters	\$2000
Rule 4309	Provision of Written Documentation of Readings and Identification of When Meters Will be Read	\$2000
Rule 4401	Billing Information, Procedures, and Requirements	\$2000
Rule 4754(a)-(e)	Annual DSM Report and Application for Bonus and Bonus Calculation	\$2000
Rule 4803(c)	Master Meter Exemption Requirements	\$2000
Rule 4004(b)-(f)	Disputes and Informal Complaints	\$1000
Rule 4202	Maintaining Heating Value, Purity and Pressure Standards	\$1000
Rule 4203(a)-(f)	Trouble Report Response, Interruptions and Curtailments of Service	\$1000
Rule 4405	Provision of Service, Rate, and Usage Information to Customers	\$1000
Rule 4406	Provision of Gas Cost Component Information to Customers	\$1000
Rule 4603(a),(d)	Gas Cost Adjustments	\$1000
Rule 4605(a),(b),(e),(f)	Gas Purchase Plans	\$1000

Rule 4607(a)	Gas Purchase Reports and Prudence Reviews	\$1000
Rule 4403(a)-(q)	Applications for Service, Customer Deposits, and Third Party Guarantees	\$500
Rule 4006	Annual Reporting Requirements	\$100
Rule 4304	Scheduled Meter Testing	\$100
Rule 4305	Meter Testing Upon Request	\$100
Rule 4402(a),(c),(d)	Meter and Billing Error Adjustments	\$100
Rule 4404(a)-(f)	Availability of Installation Payments to Customers	\$100
Rule 4407	Discontinuance of Service	\$100
Rule 4408(a)-(g); (i)	Notice of Discontinuation of Service	\$100
Rule 4409	Restoration of Service	\$100
Rule 4411(c)(IV),(d)(I), d(II),(e)	Low-Income Energy Assistance Act	\$100

**4977. – 4999. [Reserved].**

**GLOSSARY OF ACRONYMS.**

CAAM –	Cost Allocation and Assignment Manual
CCR –	Colorado Code of Regulations
C.F.R. –	Code of Federal Regulations
CPCN -	Certificate of Public Convenience and Necessity
CRCP –	Colorado Rules of Civil Procedure
C.R.S. -	Colorado Revised Statutes
e-mail -	Electronic mail
FDC -	Fully Distributed Cost
FERC –	Federal Energy Regulatory Commission
GAAP -	Generally Accepted Accounting Principles
GCA –	Gas Cost Adjustment
GPP –	Gas Purchase Plan
GPR –	Gas Purchase Report
ITP –	Intrastate Transmission Pipeline
LDC –	Local Distribution Company



MMO – Master Meter Operator  
OCC - Office of Consumer Counsel  
USOA – Uniform System of Accounts

**Glossary of Gas Measurement Units:**

Btu – British Thermal Unit  
MMBtu – 1,000,000 Btu (approximately one Mcf, depending on heat content of gas)  
Dth – Dekatherm or One MMBtu  
Therm – 100,000 Btu (approximately one Ccf, depending on heat content of gas)  
Scf - Standard cubic feet  
Ccf – 100 cubic feet (typically actual cf at meter, rather than Scf)  
Mcf – 1,000 standard cubic feet  
MMcf – 1,000,000 standard cubic feet  
Bcf – 1,000,000,000 standard cubic feet  
MMcfd – One MMcf per day

## **COLORADO DEPARTMENT OF REGULATORY AGENCIES**

### **Public Utilities Commission**

#### **4 CODE OF COLORADO REGULATIONS (CCR) 723-11**

##### **PART 11**

#### **RULES REGULATING PIPELINE OPERATORS AND GAS PIPELINE SAFETY**

##### **BASIS, PURPOSE, AND STATUTORY AUTHORITY**

The purpose of these rules is to describe the requirements for the safe operation of jurisdictional gas pipeline facilities, including construction, operations, maintenance, and operator reporting. These rules outline how the Commission will conduct pipeline safety program activities and complete the Commission's Program Certification Obligations.

The statutory authority for the promulgation of these rules can be found at §§ 40-1-103, 40-2-108, 40-2-115, 40-3-110, 40-4-109, 40-6-108, and 40-7-117, C.R.S.

##### **GENERAL PROVISIONS**

###### **11000. Scope and Applicability.**

- (a) Absent a specific statute, rules or Commission order that provides otherwise, all rules in this Part 11 (the 11000 series) shall apply to all public utilities and all municipal or quasi-municipal corporations transporting natural gas or providing natural gas service, all operators of master meter systems, and all operators or pipelines transporting gas in interstate commerce, as defined in 49 C.F.R. § 191.3.
- (b) The Public Utilities Commission conducts its Pipeline Safety Program (PSP) activities under §§ 40-1-103, 40-2-115, and 40-7-117, C.R.S. These provide the state statutory authority permitting the Commission to enter into cooperative agreements with federal agencies and to adopt and create rules to administer and to enforce the Natural Gas Pipeline Act found at 49 U.S.C. §§ 60101, et. seq. Collectively, the above referenced federal code and state statutes comprise the Commission's Program Certification Obligations.
- (c) These gas pipeline safety rules prescribe the Commissions' requirements for:
  - (I) the safe construction, operation, maintenance, and integrity management of:
    - (A) all intrastate pipeline facilities engaged in the transportation of hazardous gases, including natural gas and vaporized liquefied petroleum (LP) gas; and
    - (B) liquefied natural gas (LNG) facilities; and
  - (II) reporting requirements for operators of all facilities and pipeline systems.

- (d) These rules apply to establish and govern:
  - (I) regulations and standards for the safe transportation of hazardous gases by intrastate pipeline in Colorado;
  - (II) administration of the pipeline safety regulations by the Commission;
  - (III) reporting to the Commission by operators of specific information related to pipeline safety; and
  - (IV) adoption of federal minimum safety standards for transportation of natural gas and other gas by pipeline including:
    - (A) adoption of federal minimum safety standards for LNG facilities; and
    - (B) adoption of federal drug and alcohol testing regulations and procedures.
- (e) Except as otherwise directed, processes provided in the Commission’s Rules of Practice and Procedure, 4 CCR 723-1, including the rules governing confidentiality, shall apply to all filings made pursuant to this Part 11.
- (f) Consistent with § 40-15-107(2)(a), C.R.S., all information, documents, and copies of documents provided in connection with an audit, including any Request for Information from the PSP Chief or PSP Staff, shall be treated as confidential and shall not be made public by the Commission or any other person without prior written consent of the person providing such information, documents, or copies; or pursuant to a court order issued pursuant to § 24-72-204(5), C.R.S. If any such information, document, or copy of a document becomes the basis for, or employed within, an enforcement action pursuant to rule 11500 et seq., rules 1100-1103 of the Commission’s Rules of Practice and Procedure shall govern any claim of confidentiality in such proceeding. Any such information, document, or copy of a document that is not treated as, or deemed, confidential or highly confidential in any such proceeding thereafter shall not be treated by the Commission as confidential for any other purpose.
- (g) Nothing in these rules shall be construed to exempt pipeline operators from complying with § 9-1.5-105, C.R.S.

**11001. Definitions.**

The following definitions apply throughout this Part 11, except where a specific rule or statute provides otherwise or where the context otherwise indicates. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

- (a) “C.F.R.” means the Code of Federal Regulations.
- (b) “Confirmed discovery” means a discovery defined, as of the effective date of these rules, in 49 C.F.R. § 191.3.
- (c) “Continuing violation” or “time-dependent violation” means any violation of these rules for which a timeframe of non-compliance can be established through physical evidence and/or records that

include, but are not limited to: operator annual reports; operator compliance, operations, and maintenance records; and commission inspection, compliance and proceeding records.

- (d) “Delivered system pressure” means the system operating pressure measured at the outlet of the furthest downstream appurtenance maintained by the pipeline system operator, e.g., regulator, meter, valve, or the terminal connection of the service riser in low-pressure distribution systems.
- (e) “De minimis gas system” means a non-utility underground pipeline system used for transport and distribution of natural gas to less than ten customers within a definable private (i.e., non-municipal or public) area (e.g., a mobile home park or resort) and that does not cross a public right-of-way.
- (f) “Direct sales meter” means a meter that measures the transfer of gas to a direct sales customer purchasing gas for consumption.
- (g) “Direct sales pipeline” means a pipeline not under the jurisdiction of the Federal Energy Regulatory Commission and that runs from an intrastate or interstate transmission pipeline, a production facility, or a gathering pipeline to a direct sales meter, a pressure regulator, or an emergency valve, whichever is the furthest downstream.
- (h) “Excavation damage” means any impact that results in the need to repair or replace an underground facility due to a weakening or the partial or complete destruction of a facility, including, the protective coating; plastic pipe tracer wire; lateral support; cathodic protection; or the housing for the line device or facility
- (i) “Gas” means any material specified in these rules, including natural gas, flammable gas, toxic or corrosive gas, and petroleum gas.
- (j) “Gathering pipeline” means any pipeline determined through the use of 49 C.F.R. § 192.8.
- (k) “Hazardous facility” means a pipeline facility that, if allowed to go into operation or to remain in operation, would pose a severe or imminent risk to public safety.
- (l) “Incident” means an event defined as of the effective date of these rules, in 49 C.F.R. § 191.3, for a pipeline facility covered by 49 C.F.R. Part 192 or an emergency, as defined in § 193.2007 for an LNG facility.
- (m) “Liquefied natural gas” (LNG) means natural or synthetic gas that has methane (CH<sub>4</sub>) as its major constituent and that has been converted to liquid form for purposes of storage or transport.
- (n) “Liquid petroleum gas (LPG) system” means the liquid petroleum (LP) tanks and/or the pipeline system used to transport and distribute LP fuel gas to ten or more customers within a definable private (i.e. non-municipal or public) area (e.g., a mobile home park or resort), or less than ten customers if the system crosses a public right-of-way. LPG systems may have multiple operators if the supplying tank(s) is/are operated and maintained distinctly from the pipeline system by a different owner.
- (o) “Low-pressure distribution system” means a gas distribution system in which the gas pressure in the main is substantially the same as the pressure provided to the customer, i.e., the low-

pressure gas burning equipment of the customer may be safely and continually operated at the delivered system pressure.

- (p) “LPG Tank – CDLE OPS Inspected” means any LPG tank inspected by the Colorado Department of Labor and Employment, Division of Oil and Public Safety under the authority of the OPS rules.
- (q) “LNG facility” means a pipeline facility that is used for liquefying natural or synthetic gas and/or for transferring, storing, or vaporizing liquefied natural gas.
- (r) “Main” means a distribution line that serves, or is designed to serve, as a common source of supply for more than one service line.
- (s) “Major master meter operator (MMO)/LPG system” refers to any MMO or LPG pipeline system serving 100 or more customers.
- (t) “Mechanical excavation” means any operation in which earth is moved or removed by means of any tools, equipment, or explosives and includes auguring, backfilling, boring, ditching, drilling, grading, plowing-in, pulling-in, ripping, scraping, trenching, hydro-excavating, post/postholing, and tunneling.
- (u) “MMO gas system” means a non-utility pipeline system used for transport and distribution of natural gas to ten or more customers within a definable private (i.e., non-municipal or public) area (e.g., a mobile home park or resort), or less than ten customers if the system crosses a public right-of-way.
- (v) “Minor MMO/LPG system” means any MMO or LPG pipeline system serving between 20 and 99 customers.
- (w) “Municipality” means a city, town, or village in the state of Colorado.
- (x) “NRC” means the National Response Center of the United States Coast Guard.
- (y) “NTSB” means the National Transportation Safety Board, an independent federal agency.
- (z) “Natural Gas Pipeline Act” means the federal statute found at 49 U.S.C. §§ 60101 et seq., as amended.
- (aa) “No immediate safety impact” refers to action or inaction by operator/operator contractors on jurisdiction pipeline facilities that resulted in no immediate or imminent hazard to either the public, operator/operator contractor personnel, or pipeline system integrity.
- (bb) “Operator” means a person who is engaged in the transportation of gas, or who has the right to bury underground pipeline, or who is both engaged in the transportation of gas and has the right to bury underground pipeline, and may include an owner, such as a pipeline corporation.
- (cc) “Operator contractor” means any person or entity empowered by an operator to perform any action covered by 49 C.F.R. Part 192 and these rules.

- (dd) “Operator endangerment” refers to action or inaction by operator/operator contractors on pipeline facilities that resulted in an immediate or imminent hazard to operator/operator contractor personnel.
- (ee) “OPS” means the Office of Pipeline Safety, a unit of the PHMSA.
- (ff) “Part 192” means 49 C.F.R. Part 192 – Transportation of natural and other gas by pipeline: Minimum Federal safety standards.
- (gg) “Person” means an individual, firm, joint venture, partnership, corporation, association, municipality, cooperative association, or joint stock association, and includes any trustee, receiver, assignee, or personal representative thereof.
- (hh) “Petroleum gas” means propane, propylene, butane, (normal butane or isobutanes), and butylene or mixtures composed predominately of these gases.
- (ii) “PHMSA” means the Pipeline and Hazardous Materials Safety Administration, an agency of the United States Department of Transportation.
- (jj) “Pipeline” or “pipeline system” means all parts of those physical intrastate facilities through which gas moves in transportation, including, but not limited to, pipes, valves, and other appurtenances attached to pipes, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies that start downstream beyond the farthest most point of oil and gas production. Flowlines that are regulated by the COGCC and used for oil and gas production are not included in this definition.
- (kk) “Pipeline excavation damage prevention program” means an operator’s written program and processes to prevent damage to a pipeline by excavation, as defined in 49 C.F.R. § 192.614.
- (ll) “Pipeline facility” means new and existing intrastate pipelines, rights-of-way, and any equipment, facility, or building used in the transportation of gas, or in the treatment of gas during transportation.
- (mm) “Pipeline integrity” means the ability of a pipeline system to operate as it was verifiably designed and constructed.
- (nn) “Pipeline safety program” (PSP) means the Commission’s 49 U.S.C. § 60105(a) certified pipeline safety program.
- (oo) “Production facility” means flowline and associated equipment used at a wellsite in producing, extracting, recovering, lifting, stabilizing, initial separating, treating, initial dehydrating, disposing, and/or above ground storing, of liquid hydrocarbons, associated liquids, and associated natural hydrocarbon gases. A production facility may include flowlines up to a central delivery point directly associated with a specific producing field. To be a production facility under this rule, a flowline must be used in the process of extracting hydrocarbons and associated liquids from the ground or from facilities where hydrocarbons are produced or must be used for disposal or injection in reservoir maintenance or recovery operations.

- (pp) “PSP Chief” means the program manager of the PHMSA certified PSP of the Colorado Public Utilities Commission.
- (qq) “PSP Lead Engineer” means the senior technical staff member of the PHMSA certified PSP of the Colorado Public Utilities Commission.
- (rr) “PSP Staff” means a staff member of the PHMSA certified PSP of the Colorado Public Utilities Commission.
- (ss) “Program certification obligations” means the pipeline safety program obligations required under 49 U.S.C. § 60105(a).
- (tt) “Public endangerment” means an action or inaction by an operator/operator contractor on pipeline facilities that results in:
  - (I) interruption or delay of make safe actions designed to protect human life;
  - (II) unintended gas release requiring emergency (versus precautionary) evacuation of the public;
  - (III) an unsafe ignition of intended gas release in an area accessible to the public;
  - (IV) system overpressurization event/failure of system overpressure protection requiring emergency (versus precautionary) evacuation of the public; or
  - (V) any other hazardous situation that results in an immediate or imminent hazard to the public.
- (uu) “Roadway” means a main public artery, highway, or interstate highway.
- (vv) “Related violation” for purposes of informing the Commission authority pursuant to § 40-7-117, C.R.S., means a violation of these rules that has been proven to be directly linked with a PUC rule violation or violations by time, place, activity, and/or personnel.
- (ww) “Request for Information (RFI)” means any request from the PSP Chief or assignee to a jurisdictional operator for information associated with PSP inspection activities authorized by paragraph 11013(a).
- (xx) “Rural gathering pipeline” means any gathering pipeline located in a Class 1 location and defined in 49 C.F.R. § 192.5 or a Type B gathering pipeline located in a Class 2 area that the operator determines does not meet the Area 2 dwelling density definition in 49 C.F.R. § 192.8.
- (yy) “Single structure, above-ground MMO/LPG system” or “SSAG System” means any MMO or LPG system that is:
  - (I) a low-pressure gas distribution system;
  - (II) is comprised wholly of above-ground piping/appurtenances; and

- (III) is contained wholly within or on a single continuous structure such as an apartment building, hotel, mall, etc.
- (zz) “Small operator” means any gas distribution system operator that operates less than 1000 natural gas distribution services in the state of Colorado.
- (aaa) “Threshold MMO/LPG system” means any MMO or LPG pipeline system serving less than 20 customers.
- (bbb) “Transportation of gas” means the gathering, transmission, distribution, or storage of gas within the State of Colorado that is not subject to the jurisdiction of the Federal Energy Regulatory Commission under the Natural Gas Act.
- (ccc) “UNCC/Colorado 811” means the Utility Notification Center of Colorado.

**11002. – 11007. [Reserved].**

**11008. Incorporation by Reference.**

- (a) The Commission incorporates by reference the federal standards for reporting safety-related conditions associated with the transportation of natural gas and other gas by pipeline published in 49 C.F.R. § 191.23 (reporting safety-related conditions) and § 191.25 (filing safety-related condition reports); effective October 1, 2019. This incorporation by reference does not include later amendments to, or editions of, 49 C.F.R. Part 191.
- (b) The Commission incorporates by reference the federal safety standards for the transportation of natural gas and other gas by pipeline published in 49 C.F.R. Part 192 effective October 1, 2019. This incorporation by reference does not include later amendments to, or editions of, 49 C.F.R. Part 192.
- (c) The Commission incorporates by reference the federal safety standards for liquefied natural gas facilities that are published in 49 C.F.R. Part 193 effective October 1, 2019. This incorporation by reference does not include later amendments to, or editions of, 49 C.F.R. Part 193.
- (d) The Commission incorporates by reference the drug and alcohol testing regulations and procedures of PHMSA published in 49 C.F.R. Parts 40 and 199 effective October 1, 2019. This incorporation by reference does not include later amendments to, or editions of, 49 C.F.R. Parts 40 and 199.
- (e) Any material incorporated by reference in this Part 11 may be examined at the offices of the Commission, 1560 Broadway, Suite 250, Denver, Colorado 80202, during normal business hours, Monday through Friday, except for state holidays. Incorporated standards shall be available electronically and provided in certified copies, at cost, upon request. Restrictions on the provision of physical copies due to copyright protections may apply. The Director or the Director’s designee will provide information regarding how the incorporated standards may be examined at any state public depository library. The standards and regulations are also available from the agency, organization or association originally issuing the code, standard, guideline or rule as follows: Code of Federal Regulations: [www.govinfo.gov/help/cfr](http://www.govinfo.gov/help/cfr).



**11009. Conflict.**

In the event of a conflict regarding any administrative, enforcement, or reporting requirement of 49 C.F.R. Parts 40, 192, 193, and/or 199 and Commission Pipeline Safety Rules, the Commission's rules shall apply.

**11010. Interpretation.**

- (a) Consistent with rule 1304 of the Commission Rules of Practice and Procedure, 4 CCR 723-1, an operator may file a petition seeking a declaratory order that resolves a controversy or uncertainty regarding any statute, Commission rule, regulation, and/or Commission decision. The requestor shall include with each request, at least the following:
  - (I) the statutory provision(s), Commission rule(s), regulation(s), and/or decision(s) at issue;
  - (II) the specific instance or illustration of the application of the statutory provision(s), Commission rule(s), regulation(s), and/or decision(s) that causes the controversy or uncertainty; and
  - (III) the complete petitioner's contact information.
  - (IV) The petition may also include a request for expedited treatment if an interpretation is needed quickly and good cause exists.
- (b) Upon receipt of the petition for a declaratory order, the Commission will consider whether to accept the filing consistent with rule 1304 of the Commission's Rules of Practice and Procedure, 4 CCR 723-1.
- (c) If the petition requires interpretation of a federal regulation incorporated by reference into these rules and the Commission accepts the petition, PHMSA must review the Commission's interpretation of the federal regulation. The Commission's decision interpreting the federal regulation, and the reasons therefor, shall issue as an interim decision that shall be provided to the Office of Pipeline Safety for final review. Any response by the Office of Pipeline Safety shall be incorporated into the Commission's final decision.
- (d) Nothing in these rules prohibits an operator from contacting the PSP Chief or PSP Lead Engineer for informal assistance. Consistent with paragraph 1007(d) of the Commission's Rules of Practice and Procedure, 4 CCR 723-1, opinions expressed by the PSP Chief or PSP Lead Engineer do not represent the official views of the Commission, but are designed to aid the public and to facilitate the accomplishment of the Commission's functions. Nothing communicated by the PSP Chief or PSP Lead Engineer constitutes legal advice.

**11011. Waiver – Non-emergency.**

- (a) An owner or operator may request a waiver or a variance from any of these rules in accordance with § 40-2-115, C.R.S., 49 U.S.C. § 60118(d), and paragraph 1003(b) of the Commission's Rules of Practice and Procedure 4 CCR 723-1. Requests for waiver from the standards in 49 C.F.R. Part 192 that are incorporated by reference into these rules that are made pursuant to 49 C.F.R. Part 192.1013 are subject to the requirements of both paragraphs (b) and (c) below.

- (b) The petition shall include:
- (I) information required by rule 1003 paragraph (c);
  - (II) the specific instance or illustration of the rule's application requiring modification/waiver;
  - (III) proposed alternatives to compliance with the regulation (e.g., additional inspections and tests, shortened reassessment intervals, etc.);
  - (IV) an explanation of the necessity with supporting evidence and documentation, including:
    - (A) the mileage or footage of pipeline to be covered and the counties in which it is located;
    - (B) a description of the pipeline(s) affected by the permit (e.g., year installed, material, thickness, diameter, operating pressure, etc.);
    - (C) all pipeline other facilities such as pump and compressor stations that the permit will affect; and
    - (D) other pertinent operational history/data (e.g., leak history, corrosion history, etc.);
  - (V) a certification that the modification/waiver is consistent with pipeline safety; and
  - (VI) the complete operator contact information.
- (c) An owner or operator may file a petition for waiver under 49 C.F.R. Part 192.1013 to deviate from the standards in 49 C.F.R. Part 192 that are incorporated into these rules to alter the frequency of periodic inspections and tests on the basis of an engineering analysis and risk assessment.
- (I) A request for waiver for an alternative frequency of inspections and tests required under Part 192 will be granted if the request is found to be not inconsistent with pipeline safety. For intrastate facilities, an operator must file its proposal as a petition for waiver through the Commission's E-Filings System at least 120 days before the requested effective date.
  - (II) An owner or operator may implement an approved reduction in the frequency of a periodic inspection or test only where the operator has developed and implemented an integrity management program that provides an equal or improved overall level of safety despite the request for reduced frequency of periodic inspections.
  - (III) In addition to the information in subparagraph (b) above, each petition filed under this subsection must include the following information:
    - (A) name of the owner or operator;
    - (B) duration of the deviation proposal;
    - (C) specific regulations from which the owner or operator seeks relief;

- (D) a description of the pipeline for which the deviation is sought, including:
    - (i) the mileage or footage of the pipeline to be covered by the request and the counties in which it is located;
    - (ii) the year the pipeline was installed;
    - (iii) all pipeline facilities that the request will affect; and
    - (iv) the material, thickness, diameter, and operating pressure of the pipeline;
  - (E) alternatives proposed for compliance with the regulation (e.g., additional inspections and tests, shortened reassessment intervals); and
  - (F) a certification that operation of the owner or operator's pipeline under the requested alternative frequency of periodic inspections and tests would not be inconsistent with pipeline safety and will provide an equal or greater overall level of safety.
- (IV) After receiving notice of the petition, the PSP Chief will confer with the Office of Pipeline Safety on the waiver requested by the owner or operator. The PSP Chief will file a notice in the petition proceeding indicating whether the request should be accepted by the Commission and if so, whether additional conditions or limitations that are relevant and in the public interest should be adopted. The Commission shall consider the petition for waiver and the notice filing of the PSP Chief in rendering a decision.
- (d) PHMSA Review: If the Commission grants a petition filed by an owner/operator for a waiver of a federal rule that is incorporated into the Commission rules, PHMSA must review the Commission's decision, except for petitions for waiver covered by paragraph (c) above. The Commission's decision granting a waiver request that requires PHMSA review, and the reasons therefor, shall issue as an interim decision that shall be provided to the Office of Pipeline Safety for final review pursuant to 49 U.S.C. § 60118(d). Any response by the Office of Pipeline Safety shall be incorporated into the Commission's final decision.

**11012. Waiver – Emergency.**

- (a) An operator may file a petition to request an emergency waiver or variance in situations that require expedited review that is otherwise inconsistent with § 40-2-115, C.R.S., 49 U.S.C. § 60118(d), and the Commission's Rules of Practice and Procedure.
- (b) An emergency waiver request will be granted if it is in the public interest, is not inconsistent with pipeline safety, and is necessary to address an actual or impending emergency involving pipeline transportation, including emergencies caused by natural or manmade disasters.
- (c) An emergency waiver is an order by which the Commission may temporarily modify compliance with state pipeline regulations for affected pipeline owners or operators and the Commission may waive compliance with a safety regulation if, after receiving notice on an incorporated federal rule, PHMSA concurs in the action.

- (d) The Commission will determine on a case-by-case basis what duration of waiver or variance is necessary to address the emergency. However, as required by statute, no emergency waiver may be issued for a period exceeding 60 days. Each emergency waiver will automatically expire on the date stated in the Commission's decision.
- (e) An operator may request an emergency Special Permit modifying or waiving of any of these rules by submitting a written request as follows.
  - (I) If the request concerns a Colorado-specific rule then no subsequent review by PHMSA is required. The requestor shall file a petition for the emergency waiver with the Commission using one of the following methods:
    - (A) the Commission's E-Filings System; or
    - (B) express mail/overnight courier to Doug Dean, Director of the Colorado Public Utilities Commission, 1560 Broadway, Suite 250, Denver, CO 80202.
  - (II) If the request concerns a federal rule incorporated by reference into these rules, a review by PHMSA is required. The requestor shall submit a petition for the emergency waiver directly to the Commission using one of the methods described above and to PHMSA using any of the following methods:
    - (A) direct fax to the PHMSA Crisis Management Center at: 202-366-3768;
    - (B) direct e-mail to PHMSA at: [phmsa.pipeline-emergencyspecpermit@dot.gov](mailto:phmsa.pipeline-emergencyspecpermit@dot.gov); or
    - (C) express mail/overnight courier to the Associate Administrator for Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue, SE East Building, Washington, DC 20590.
- (f) The requestor shall include with each emergency waiver petition:
  - (I) the information required by rule 1003 paragraph (c);
  - (II) an explanation of the actual or impending emergency;
  - (III) the specific instance or illustration of the rule's application requiring modification/waiver;
  - (IV) proposed alternatives to compliance with the regulation (e.g., additional inspections and tests, shortened reassessment intervals, etc.);
  - (V) to the extent possible, as much of the information as is required in paragraph 11011(c); and
  - (VI) measures to be taken after the emergency situation or permit expires, whichever comes first, that will confirm/assure long-term operational reliability of the facility impacted by the Special Permit.

- (g) The emergency waiver is effective upon final order by the Commission or the PHMSA Administrator for Pipeline Safety, as appropriate to the review.

**11013. Inspections and Investigations.**

- (a) Upon presenting appropriate credentials, a representative of the PSP may enter upon, inspect, and examine, at reasonable times, and in a reasonable manner, the records, facilities, and properties of pipeline operators to the extent such records, facilities, and properties are relevant to determining the compliance of such operators with the requirements of these rules or Commission orders.
- (b) Prior to an inspection or investigation, the PSP Chief or assignee shall notify an operator. Except in emergency situations, the operator shall have an opportunity to respond to the notification prior to the initiation of an inspection or investigation relating to any jurisdictional pipeline facility, including the operator's right of way or easement, new and existing piping, valves, and other above ground appurtenances attached to pipes, or, upon request of PHMSA, an interstate pipeline to determine compliance with 49 U.S.C. §§ 60101 et. seq., with these rules, and with applicable Commission orders.
- (c) Inspections and investigations are necessitated by the existence of one or more of the following circumstances:
  - (I) routine scheduling by the PSP Chief, PSP Lead Engineer, or other designee;
  - (II) pipeline-related incidents and events reported to the PSP in accordance with rules 11101 through 11103;
  - (III) a complaint received from a member of the public and verified by the PSP Chief or Lead Engineer as related to a jurisdictional pipeline facility and involving a discrete and auditable matter potentially impacting public safety;
  - (IV) information obtained from a previous inspection; or
  - (V) when deemed appropriate by the Commission or PHMSA under their respective authorities.
- (d) After an inspection, the PSP Chief will pursue one of the following:
  - (I) an inspection close-out indicating that no further action will be taken on final inspection findings;
  - (II) a RFI indicating that the inspection is ongoing without final inspection findings, to be answered within the timeframe requested in the RFI, typically 30 calendar days from the operator's receipt of the RFI unless otherwise indicated and agreed to by the PSP Chief and the operator; or
  - (III) a compliance action taken on final inspection findings as described in rules 11502 and 11503.

- (e) If a representative of the PSP investigates an incident involving a pipeline facility, the PSP Chief of the Commission may request that the operator make available to the representative all records and information that directly or indirectly pertain to the incident, including integrity management plans and test results, and that the operator afford all reasonable assistance in the investigation.
- (f) To the extent necessary to carry out the responsibilities the Program Certification Obligations, the PSP may require testing of portions of pipeline facilities that have been involved in, or affected by, an incident. However, before exercising this authority and accepting responsibility, the PSP shall make every effort to negotiate a mutually acceptable plan with the owner of those facilities and, where appropriate, other local and state fire and safety authorities, PHMSA, the NTSB, and any known third parties for performing the testing.

#### **11014. Advisory Bulletins.**

PSP advisories or PHMSA advisory bulletins are periodically drafted and communicated to affected operators as a result of circumstances identified by the PSP, PHMSA, NTSB, or industry with the potential to become pipeline system safety risks. Operators should review these bulletins for relevancy to their individual pipeline system operations.

#### **11015. – 11099. [Reserved].**

### **INFORMATION REQUIRED OF OPERATORS**

#### **11100. Submission of Reports and Notices - General.**

- (a) For all annual reporting, the PSP will access the PHMSA Pipeline Data Mart beginning on March 16 of every year to confirm operator submittals. Failure to meet Annual Report submittal deadlines will result in issuance in a Warning Notice; failure to meet submittal deadlines in two successive calendar years will result in the issuance of a NPV against the operator.
- (b) For all specialized reporting, failure to meet submittal deadlines and requirements will result in issuance in a Warning Notice or a NPV against the operator.
- (c) For all electronic reporting to PHMSA, if this reporting method imposes an undue burden and hardship, an operator may submit a written request for an alternative reporting method to: Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, PHP-20, 1200 New Jersey Avenue, SE, Washington, DC 20590. The request must describe the undue burden and hardship. PHMSA will review the request and may authorize, in writing, an alternative reporting method. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202-366-8075; electronically to [informationresourcesmanaer@dot.gov](mailto:informationresourcesmanaer@dot.gov); or make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received.

#### **11101. Submission of Reports and Notices.**

- (a) Operators must submit all required reports, as applicable, within the specified deadline(s) for the following occasions requiring specialized reporting or notice. Any reporting shall be in addition to, or supplemental to, reporting required under federal law and shall not be duplicative.

(b) Incident reporting.

- (I) Written reports of all incidents required to be reported under these rules must be submitted as soon as practicable but not more than 30 days after detection of the incident.
- (II) Each operator submitting information to PHMSA via its electronic portal shall also file such information with the Commission in accordance with subparagraph 1204(a)(III) of the Commission's Rules of Practice and Procedure in the repository proceeding opened for such reporting purpose.
- (III) Each operator that submits information PHMSA via alternative methods shall file copies of this information with the Commission.
- (IV) Each operator of a distribution pipeline system, excepting MMO/LPG systems, shall submit the Incident Report (PHMSA F 7000.1) to PHMSA using its electronic portal at <https://portal.phmsa.dot.gov>.
- (V) Each operator of an MMO/LPG system shall submit a Small Operator Incident Report (PSP SOIR) to the Commission through its E-Filings System in the repository proceeding opened for such reporting purposes.
- (VI) Each operator of a transmission or Type A or Type B gathering system (i.e., excepting rural gathering), shall submit the Incident Report (PHMSA F 7100.2) to PHMSA using its electronic portal at <https://portal.phmsa.dot.gov>.
- (VII) Each operator of a LNG facility shall submit the Incident Report (PHMSA F 7100.3) to PHMSA using its electronic portal at <https://portal.phmsa.dot.gov>.
- (VIII) When additional relevant information is obtained after the report is submitted under paragraph (a) or (b) of this rule, the operator shall make supplementary reports as deemed necessary with a clear reference by date and subject to the original report. The operator shall notify the PSP Chief of all supplementary reporting.

(c) Safety-related condition (SRC) reporting.

- (I) Written reports of SRC's must be submitted in accordance with the timelines established in 49 C.F.R. Part 191, § 191.25(a).
- (II) Written reports of SRC's must be submitted with information as required in 49 C.F.R. Part 191, § 191.25(b).
- (III) Any operator filing a SRC report as required by 49 C.F.R. Part 191, § 191.23 (Reporting SRC's) and §191.25 (Filing SRC reports) with PHMSA shall also concurrently inform the PSP Chief through e-mail at [dora\\_copuc\\_pipeline\\_safety@state.co.us](mailto:dora_copuc_pipeline_safety@state.co.us) and submit the SRC report to Commission through its E-Filings System in accordance with subparagraph 1204(a)(III) of the Commission's Rules of Practice and Procedure in the repository proceeding opened for such reporting purposes no later than close of the next business day.

- (d) Pipeline damage and of locate information reporting. Each operator subject to the requirements of these rules and Colorado Revised Statutes Title 9, Article 1.5 (the “Colorado One-call Law”) shall submit the PSP Damage and Locate Report (PSP DLR) to the Commission through its E-Filings System in accordance with subparagraph 1204(a)(III) of the Commission’s Rules of Practice and Procedure in the repository proceeding opened for such reporting purposes.

**11102. Verbal Reporting of Pipeline Incidents and Events.**

- (a) Colorado pipeline incidents.
- (I) All pipeline and LNG facility operators must provide expedited reporting of a pipeline incident as soon as possible after confirmed discovery; not to exceed two hours after confirmed discovery.
  - (II) If the expedited reporting time for a pipeline incident exceeds two hours after confirmed discovery, the operator shall provide a written explanation for the time exceedance to the PSP Chief within ten business days after the incident.
  - (III) All operators must report a pipeline incident to:
    - (A) the NRC via telephone at 800-424-8802; and
    - (B) after an NRC control number is issued for the incident, to the PSP Staff via telephone at 303-894-2854.
  - (IV) A telephonic report made pursuant to this rule must include the following information:
    - (A) the NRC control number;
    - (B) the name and telephone number of the operator and the contact for more information on the incident;
    - (C) the location of the incident or event;
    - (D) the date and time of the incident or event;
    - (E) the number of fatalities and personal injuries, if any; and
    - (F) all other significant facts that are known by the person making the report that are relevant to the cause of the incident and the extent of the damage.
- (b) Colorado pipeline events.
- (I) All pipeline operators, including operators of gathering pipelines in Class 1 areas, LNG facilities/systems, and MMO/LPG systems, must provide expedited reporting of pipeline events described below as soon as possible after discovery; not to exceed two hours after confirmed discovery.



- (II) If the expedited reporting time for a pipeline event exceeds two hours after confirmed discovery, the operator shall provide a written explanation for the exceedance to the PSP Chief within ten business days after the event.
- (III) All pipeline operators must report the following pipeline events to the PSP Staff via telephone at 303-894-2854:
  - (A) an unplanned/emergency event that occurs on the pipeline system that results in the evacuation of 50 or more people from a normally occupied building or property;
  - (B) an unplanned/emergency event that occurs on the pipeline system that results in the closure of all lanes in either direction of a roadway or railroad;
  - (C) an unplanned/emergency event that occurs on the pipeline system that results in the evacuation of four or more residential structures;
  - (D) an unplanned/emergency event that occurs on the pipeline system that results in a service outage of 100 or more customers;
  - (E) an event that requires active soil vapor extraction for a period exceeding 48 hours as measured from the time the extraction device is turned on at the site until the operator determines soil vapor extraction is no longer necessary;
  - (F) a MAOP-exceedance event that requires the operator, pursuant to its procedures, to implement follow-up actions such as a leak survey; or
  - (G) an event that, in the opinion of the operator, requires courtesy notification to the PSP.

**11103. Submission of Annual Reports.**

- (a) On or before March 15 of each year, each operator shall file with the Commission an annual report for the preceding calendar year. The reports shall be filed in accordance with subparagraph 1204(a)(III) of the Commission's Rules of Practice and Procedure.
- (b) Each operator of a distribution pipeline system, excepting MMO/LPG systems, shall submit the Annual Report (PHMSA F 7100.1-1) to PHMSA using its electronic portal at <https://portal.phmsa.dot.gov>.
- (c) Each operator of an MMO/LPG system shall submit the Small Operator Annual Report (PSP SOAR) to the Commission through its E-Filings System in the repository proceeding opened for annual reports.
- (d) Each operator of a transmission or Type A or Type B gathering system (i.e., excepting rural gathering), shall submit the Annual Report (PHMSA F 7100.2-1) to PHMSA using its electronic portal at <https://portal.phmsa.dot.gov>.

- (e) Each operator of a LNG facility shall submit the Annual Report (PHMSA F 7100.3-1) to PHMSA using its electronic portal at <https://portal.phmsa.dot.gov>.

**11104. – 11199. [Reserved].**

**SAFETY STANDARDS FOR HAZARDOUS GAS PIPELINE SYSTEMS**

**11200. Standards – General.**

An operator shall comply with these rules and the minimum safety standards for the transportation of natural gas and other gas by pipeline that are incorporated by reference in rule 11008, as applicable.

**11201. Pipeline Excavation Damage Prevention.**

- (a) An operator, including operators of MMO/LPG and rural gathering pipeline systems, must be a Tier 1 Member at the UNCC/Colorado 811 if any part of the pipeline system is located in any public or railroad right-of-way.
- (b) An operator, excluding operators of MMO/LPG pipeline systems but including operators of rural gathering pipeline systems, must report underground facility damages to the UNCC/Colorado 811 in accordance with § 9-1.5-103(7), C.R.S.
- (c) Operators of MMO/LPG and rural gathering pipeline systems must install and maintain pipeline markers, labeled according to § 192.707(d), at each crossing of a public road or railroad right-of-way.
- (d) An operator, excluding operators of MMO/LPG and rural gathering pipeline systems, must have written guidelines regarding when and how civil penalties are pursued under § 9-1.5-104.5, C.R.S. against persons damaging their pipeline facilities, and when and how penalty alternatives are implemented. At a minimum, the collection of data on and subsequent analysis of the causes of excavation damages to comply with 49 C.F.R. § 192.614 (a). These guidelines must provide for:
- (I) recording information about pipeline damages that includes identification of the responsible party and the probable cause of each excavation damage in the following categories:
    - (A) inadequate excavation practices;
    - (B) no locate requested;
    - (C) inaccurate/missing locate – Operator located; and
    - (D) inaccurate/missing located – Contractor located.
  - (II) Analysis of the information in (a) above that allows for the identification of acute risk parties that have caused multiple pipeline damages in the preceding 18 months; and

- (III) analysis of the information in (a) above that allows for the identification of chronic risk parties that have caused multiple pipeline damages over (a) time period(s) greater than 18 months.
- (e) The PSP will pursue compliance action against an operator under § 192.614(c)(5) whose excavation damages due to inaccurate or missing locates:
  - (I) were found through investigation to be contributory to a pipeline incident;
  - (II) were found through investigation to be contributory to a pipeline event that, in the opinion of the PSP, represented a major threat to public safety; or
  - (III) were found to represent an excessive risk to the operator's pipeline by the analyses required by subparagraphs 11201(d)(II) and (III).

**11202. Direct Sales Pipelines.**

Unless otherwise specified in this rule, direct sales pipelines are classified as intrastate transmission pipelines and subject to these rules and all applicable 49 C.F.R. Part 192 rules, as incorporated.

**11203. Small Operator Systems.**

- (a) General requirements.
  - (I) Unless otherwise specified in this rule, a small operator system is subject to these rules and all applicable 49 C.F.R. Part 192 rules, as incorporated.
  - (II) Unless otherwise specified in this rule, any operator of a small operator system may opt into the prescriptive distribution integrity management provisions of paragraph (h) of this rule via written request to the PSP Chief or PSP Lead Engineer.
- (b) Standards applied to de minimis gas systems.
  - (I) Unless otherwise specified in this rule, de minimis gas systems are exempt from these rules and 49 C.F.R. Part 192 rules, as incorporated.
  - (II) System expansion.
    - (A) Operators of de minimis gas systems must apply for Commission approval prior to any system expansion.
    - (B) Operators of de minimis gas systems are prohibited from expanding the system unless proper permits are issued by the appropriate plumbing inspection authority.
  - (III) Leak surveys.

- (A) De minimis gas systems must be leak surveyed with equipment using instruments and techniques suitable for detecting fugitive natural gas, or LPG in gaseous/vapor form, as applicable, once every two years.
  - (B) Records and results of all leak surveys will be kept for the life of the system.
- (IV) System repairs.
- (A) An operator of a de minimis gas system must repair all hazardous pipeline leaks immediately upon discovery.
  - (B) An operator of a de minimis gas system must repair all other pipeline system leaks within 45 days of discovery.
  - (C) All system repairs must be completed by a plumber, gas utility technician, or utility contractor qualified to install and repair underground gas systems.
  - (D) Prior to any leak repair, the operator of a de minimis gas system must acquire a plumbing permit issued by the appropriate plumbing inspection authority. If a leak has been repaired immediately due to a public safety hazard, the repair must be permitted after the fact and will be left exposed for inspection by the appropriate plumbing inspection authority or a PSP Inspector.
- (c) Standards applied to SSAG systems.
- (I) Any SSAG system is compliant with these rules if the system has been inspected and passed a system safety inspection within the last five years by one of the following means:
    - (A) inspection by the PSP;
    - (B) inspection by the Fire Department or Fire Marshall using NFPA 54 (National Fuel Gas Code), NFPA 101 (Life Safety Code), or a written equivalent standard; or
    - (C) inspection by the plumbing entity using the International Fuel Gas Code or a written equivalent standard.
  - (II) Record of the final, approved inspection of the gas system installation shall be kept for the life of the system.
  - (III) Records of all subsequent inspections shall be maintained and available for PSP inspection for a minimum of ten years from the date of inspection.
- (d) Standards applied to LPG systems.
- (I) The PSP will deem any LPG tank – CDLE OPS Inspected to be compliant with these rules, subject to the following restrictions:
    - (A) the tank has passed the CDLE OPS inspection; and

- (B) the tank has been inspected within the last five calendar years.
- (II) Leak surveys and leak pinpointing must use instruments and techniques suitable for detecting fugitive LPG in gaseous/vapor form.
- (e) Standards applied to Major MMO/LPG systems.
  - (I) Major MMO/LPG systems must acquire a PHMSA Operator Identification Number.
- (f) Standards applied to Minor MMO/LPG systems.
  - (I) Except as provided in subparagraph 11203(h)(VII), Minor MMO/LPG systems are subject to the P-DIMP of paragraph 11203(h).
- (g) Standards applied to threshold MMO/LPG systems.
  - (I) Except as provided in subparagraph 11203(h)(VII), Threshold MMO/LPG systems are subject to the P-DIMP of paragraph 11203(h).
- (h) Prescriptive distribution integrity management program (P-DIMP).
  - (I) Operators subject to this rule shall be subject to a P-DIMP consisting of an evaluation and a plan.
  - (II) Operators subject to this rule shall have a P-DIMP evaluation performed by the PSP at least once every five years; sooner when system history or PSP inspection indicates a change in any operating condition that necessitates a new P-DIMP evaluation.
  - (III) The P-DIMP shall explicitly consider, prioritize, and rank system risks based on the following:
    - (A) number of affected persons;
    - (B) physical system parameters including but not limited to:
      - (i) materials;
      - (ii) delivered system pressure, including whether the system is a low-pressure distribution system; and
      - (iii) leak and leak repair history.
    - (C) Operational system parameters including, but not limited to:
      - (i) compliance history of the current legal operator;
      - (ii) system records;

- (iii) availability of appropriate tools and equipment to operate gas pipeline system;
  - (iv) availability of trained and/or qualified personnel to operate and maintain the system during normal operations; and
  - (v) availability of trained and/or qualified personnel to operate the system during emergencies.
- (IV) All physical and operational parameters that are unknown at the time of the P-DIMP evaluation shall be considered by the PSP to pose the maximum public safety risk that is reasonably associated with the unknown parameter.
- (V) Following a completed P-DIMP evaluation, all operators of a Threshold MMO/LPG system or Minor MMO/LPG system shall be subject to P-DIMP unless the operator opts out of a P-DIMP as allowed in subparagraph 11203(h)(VII).
- (VI) The P-DIMP shall prescribe operations and maintenance activities appropriate to maximize system integrity and minimize the public safety risk posed by the operation of the system.
- (VII) P-DIMP Opt-out. An operator of a Threshold MMO/LPG system or Minor MMO/LPG system may opt-out of P-DIMP at any time by petitioning the Commission to be regulated as a Major/MMO/LPG system.

#### **11204. Conversion to Service.**

A pipeline previously used in service not subject to 49 C.F.R. Part 192 qualifies for service subject to 49 C.F.R. Part 192 if the operator prepares and follows a written procedure addressing the requirements of 49 C.F.R. § 192.14. The operator shall make its written procedures and applicable records available to PSP Staff upon request.

#### **11205. – 11299. [Reserved].**

### **SAFETY STANDARDS FOR LIQUEFIED NATURAL GAS (LNG) SYSTEMS**

#### **11300. Standards – General.**

An operator shall comply with the safety standards for liquefied natural gas facilities that are incorporated by reference in paragraph 11008(c).

#### **11301. – 11399. [Reserved].**

### **SAFETY STANDARDS FOR PIPELINE OPERATOR DRUG AND ALCOHOL PROGRAMS**

#### **11400. Standards – General.**

An operator shall comply with the standards for pipeline operator drug and alcohol programs that are incorporated by reference in paragraph 11008(d).

**11401. – 11499. [Reserved].**

**RULE VIOLATIONS, CIVIL PENALTIES, AND COMPLIANCE ACTIONS**

**11500. Violations - General.**

- (a) Violations of these rules are determined by inspections, audits, and/or testing performed under rule 11013 that indicate a compliance deficiency or deficiencies with respect to rule requirement(s).
- (b) Violations will be examined by the PSP Chief to determine impact category resulting from the violation: no immediate safety impact, incident, public endangerment, operator endangerment, or a loss/reduction of pipeline integrity.
- (c) Alleged rule violations are deemed “probable” until completion of an appropriate enforcement action, including any Commission hearing or proceeding.
- (d) The PSP Chief or PSP Staff may use the determination in paragraph (a) as a prima facie basis for opening a complaint proceeding pursuant to paragraph 1302(g) of the Commission’s Rules of Practice and Procedure.

**11501. Violations – Civil Penalties.**

- (a) This rule shall apply to violation(s) that would have otherwise been discovered by a prudent operator in the normal course of business. This is the lowest degree of culpability for which operators may be penalized and does not limit the Commission from penalizing operators for higher degrees of culpability.
- (b) An operator who violates these rules or an order of the Commission issued under these rules may be subject to civil penalties as follows:
  - (I) civil penalties shall not exceed \$100,000 per instance of violation;
  - (II) each day of a continuing violation constitutes a separate instance of violation; and
  - (III) in the case of a group or series of related violations, the aggregate amount of such penalties shall not exceed \$1,000,000.
- (c) Civil penalties – general. The PSP Chief may propose that the Commission assess civil penalties against an operator following a PSP inspection and/or investigation that has established specific pipeline safety rule violation(s) and a time-dependent or time-independent nature of the violations(s).
- (d) Civil penalties – calculation. To provide consistency and specificity, civil penalties shall be calculated through the formulaic method as follows.
  - (I) Time-dependent/history based activity violations.

- (A) Violations determined by an action or activity not performed or failure to be performed in accordance with rule or procedure:
- (i) the penalty is assessed by individual action or activity required by rule or procedure;
  - (ii) the penalty amount is calculated by the equation:

$$B \times t \times F_{ph} \times F_{hh} \times F_i,$$

where:

B = Base penalty of \$1 per day for the activity associated with the violation

t = Timeframe of non-compliance, in days

$F_{ph}$  = Pertinent/related system history factor, as determined in the Time-Dependent Violation Impact Factor Table

$F_{hh}$  = Hazardous history factor, as determined in the Time-Dependent Violation Impact Factor Table

$F_i$  = Incident history factor, as determined in the Time-Dependent Violation Impact Factor Table

- (B) Time-dependent violation impact factor table:

<b>Time-Dependent Violation Impact Factor Table</b>			
FACTOR	THRESHOLD	Factor multiplier if threshold <i>NOT</i> met	Factor multiplier if threshold met
$F_{ph}$	The violation was associated with other inspection findings that indicated related effects on pipeline system integrity (e.g., leaks, corrosion, PHMSA Advisory Bulletin, missing records, etc.)	1	5
$F_{hh}$	The violation was associated with other inspection findings that indicated related effects on public safety (e.g., hazardous leaks, safety-critical activity, safety-related condition, etc.)	1	10
$F_i$	The violation was associated with other inspection findings that indicated the violation contributed to an Incident	1	20

- (II) Time-independent/outcome-based violations.



- (A) Violations determined by a failure to follow or inadequate/missing operator procedures:
  - (i) the penalty is assessed by individual or group actions or activities required by rule or procedure;
  - (ii) the penalty amount is calculated by the equation:

$$B \times F_{\text{impact}}, \text{ where}$$

$$B = \$5,000 \text{ base penalty per instance of violation}$$

$F_{\text{impact}}$  = Time-independent Impact Factor as determined in the Time-Independent Violation Impact Factor Table

- (B) Violations determined by an unqualified worker performing operations, maintenance, or construction tasks:
  - (i) the penalty is assessed per worker and specific individual qualification required by rule or procedure; and
  - (ii) the penalty amount is calculated by the equation:

$$B \times F_{\text{impact}}, \text{ where}$$

$$B = \$5,000 \text{ base penalty per instance of violation}$$

$F_{\text{impact}}$  = Time-independent Impact Factor as determined in the Time-Independent Violation Impact Factor Table

- (C) Rule 11201 violations:
  - (i) the penalty is assessed per applicable paragraph of rule 11201;
  - (ii) the penalty amount is calculated by the equation:

$$B \times F_{\text{impact}}, \text{ where:}$$

$$B = \$5,000 \text{ base penalty per instance of violation}$$

$F_{\text{impact}}$  = Time-independent Impact Factor as determined in the Time-Independent Violation Impact Factor Table

- (D) Missing or incomplete records:
  - (i) the penalty is assessed by grouped action or activity required by rule or procedure;

- (ii) the penalty is assessed by applicable inspection focus, i.e., district operating area, operating unit, or total operator system;
- (iii) the penalty is calculated based on the estimated volume of missing or incomplete records:
  - a. Gross Incompletion (Record incompleteness/absence  $\geq$  10 percent or complete record absence for a required code segment) = \$10,000/code/segment/calendar year;
  - b. Major Incompletion (Record incompleteness/absence  $\geq$  5 percent and  $<$  10 percent for a required code segment) = \$5,000/code/segment/calendar year;
  - c. Significant Incompletion (Record incompleteness/absence  $\geq$  2 percent and  $<$  5 percent for a required code segment) = \$2,500/code/segment/calendar year.

(E) Time-independent violation impact factor table:

<b>Time-Independent Violation Impact Factor Table</b>	
THRESHOLD	Factor multiplier if threshold met
The violation resulted in no immediate safety impact	1
The violation resulted in operator endangerment; operator property loss > \$10,000; or emergency (versus precautionary) actions by the operator necessary to protect system integrity	5
The violation resulted in public endangerment; non-operator property loss > \$10,000; or a loss of pipeline integrity	10
The violation resulted in an Incident	20

- (e) Multiple calculated penalties will be summed to compute a final civil penalty.
- (f) The PSP Chief may propose to the Commission the assessment of a revised final civil penalty lower than the summed calculated penalties based on the operator’s documented and verifiable efforts to mitigate the violations(s) and improve overall system safety and integrity.
- (g) The calculated and final civil penalty amounts shall be illustrated in the NPV to the operator.

- (h) Nothing in this rule shall prohibit the Commission from the calculation and/or assessment of a new final civil penalty during a formal hearing process.
- (i) The Commission may assess doubled or tripled civil penalties against any public utility, as provided by § 40-7-113.5(3), C.R.S., § 40-7-113.5(4), C.R.S., and this rule.
  - (I) The Commission may assess any public utility a civil penalty containing doubled penalties only if:
    - (A) the public utility has admitted liability by paying the proposed final civil penalty for, or has been adjudicated by the Commission in an administratively final written decision to be liable for, engaging in prior conduct that constituted an intentional violation of a statute in Articles 1 to 7 and 15 of Title 40, C.R.S., a Commission rule, or a Commission order;
    - (B) the conduct for which doubled civil penalties are sought violates the same statute, rule, or order as conduct for which the public utility has either admitted liability by paying the civil penalty assessment, or been adjudicated by the Commission in an administratively final written decision to be liable; and
    - (C) the conduct for which doubled civil penalties are sought occurred within one year after conduct for which the public utility has either admitted liability by paying the civil penalty assessment, or been adjudicated by the Commission in an administratively final written decision to be liable.
  - (II) The Commission may assess any public utility a civil penalty containing tripled penalties only if:
    - (A) the public utility has admitted liability by paying the proposed final civil penalty for, or has been adjudicated by the Commission in an administratively final written decision to be liable for, engaging in prior conduct that constituted two or more intentional violations of a statute in Articles 1 to 7 and 15 of Title 40, C.R.S., a Commission rule, or a Commission order;
    - (B) the conduct for which tripled civil penalties are sought violates the same statute, rule, or order as conduct for which the public utility has either admitted liability by paying the civil penalty assessment, or conduct for which the public utility has been adjudicated by the Commission in an administratively final written decision to be liable, in at least two prior instances; and
    - (C) the conduct for which tripled civil penalties are sought occurred within one year after the two most recent instances of conduct for which the public utility has either admitted liability by paying the civil penalty assessment, or been adjudicated by the Commission in an administratively final written decision to be liable.

**11502. Compliance Action - General.**

- (a) Initiation. Upon discovery of a probable violation of these rules, the PSP Chief will initiate a compliance action intended to remediate and prevent recurrence of the violation.
- (b) Intent. A compliance action is intended to minimize the realized or potential impacts of the violation on public safety and/or the integrity of the pipeline system or LNG facility and will be consistent with the intent of § 40-7-117, C.R.S. After the Commission issues a notice, an operator shall have the opportunity to respond and to cure any violation of these rules.
- (c) Structure. All compliance action notices to a pipeline operator must include:
  - (I) a statement of the law, rule(s), or order(s) that the operator is alleged to have violated; and
  - (II) a statement of the facts upon which the determination of violation is based and recommendations on actions that may be taken by the operator to remedy further noncompliance.
- (d) Service of process. Service of process shall be undertaken pursuant to rule 1205 of the Commission's Rules of Practice and Procedure and § 40-6-108, C.R.S.

**11503. Compliance Action – Warning Notice.**

In the instance of a probable violation of these rules that has no previous enforcement history and poses a low risk to public safety and/or pipeline/LNG facility integrity, as determined by current regulation, industry standard, or other relevant objective technical standard, the PSP Chief will issue a Warning Notice to an operator. The Warning Notice will advise the operator of the probable violation, require the operator to correct the probable violation or be subject to further enforcement action under these rules, and may require a formal written response from the operator on their corrective action plan so that a follow-up inspection can be scheduled.

**11504. Notice of Probable Violation (NPV).**

- (a) In the instance of a probable violation of these rules that has a previous enforcement history or poses a moderate to severe risk to public safety or pipeline or LNG facility integrity, as determined by current regulation, industry standard, or other relevant objective technical standard, the PSP Chief may issue a NPV to an operator. The NPV will advise the operator of the probable violation and include the following sections:
  - (I) a statement of inspection findings that incorporates the requirements of rule 11502, above;
  - (II) a statement of the regulatory interpretation upon which the determination of probable violation is based;
  - (III) a civil penalty calculation using rule 11501 stating separately for each probable violation the maximum penalty amount provided and a total penalty;

- (IV) the PSP Chief's civil penalty assessment evaluation consistent with § 40-7-117, C.R.S. that includes a conclusion for or against assessment of the civil penalty in whole or in part;
  - (V) a final recommended civil penalty assessment;
  - (VI) as appropriate, the NPV will offer the operator a proposed alternative enforcement in lieu of the civil penalties, in whole or in part. The proposed alternative enforcement will describe the process in sufficient detail to explain how it will provide for the improvement of public safety;
  - (VII) as appropriate, the NPV will include a compliance directive that prescribes specific actions to be taken by the operator within a specific timeframe to correct the violation; and
  - (VIII) a description of the operator's response options.
- (b) The NPV shall be filed in a new proceeding and shall serve as notice of the alleged probable violation and potential actions to be taken by the Commission.
- (c) Within 30 days after receipt of a NPV issued pursuant to the rule, an operator shall file in the proceeding its response with one of the following options.
- (I) The operator may admit the NPV through the following filings and actions:
    - (A) the operator shall pay any proposed final civil penalty in full; and
    - (B) the operator shall agree to any proposed compliance directive.
  - (II) The operator may request the Commission consider an offer in compromise to the NPV through the following filings and actions:
    - (A) the operator may request reconsideration, reissuance, or dismissal of the initial NPV through submittal of a written explanation, information, or other material in response to the allegations contained in the NPV; in objection to the proposed compliance directive; or in mitigation of the proposed final civil penalty; or
    - (B) the operator and the PSP Chief may jointly file a stipulation and settlement agreement pursuant to rule 11507, resolving the allegations in the NPV for the Commission's consideration.
  - (III) The operator may oppose the NPV, or any part thereof. The operator shall file its response opposing the allegations in the NPV in the proceeding and provide all relevant information it finds addresses the issues raised. If an operator opposes any alleged violation in the NPV, the matter shall be set for hearing. When applicable and appropriate, such appeal will stay the duration of the noncompliance for purposes of any penalty calculation contingent upon interim operator actions to cure the alleged violation(s).

- (d) If the operator fails to respond as provided in this rule within 30 days of the NPV, the NPV shall be deemed opposed by the operator and shall be set for hearing as prescribed by subparagraph (c)(III) above.

**11505. Request for Amendment (RFA).**

- (a) If an inspection, audit, or investigation reveals that an operator's plans or procedures required by these rules may be insufficient to ensure the compliant operation of a pipeline or LNG facility, the PSP Chief may issue an RFA.
- (b) The RFA shall serve as notice from the Commission of potential inadequacies and serve to facilitate and expedite necessary plan or procedure revision(s) and implementation so that pipeline operation, maintenance, training, or emergency response is not compromised. The RFA shall specify the potential inadequacies and may:
  - (I) specify a proposed timeline for revised plan implementation based on the impact to pipeline operations; and
  - (II) provide an opportunity for response.

**11506. Notice of Amendment (NOA).**

- (a) If an inspection, audit, or investigation reveals that an operator's plans or procedures required by these rules are inadequate to ensure the safe operation of a pipeline or LNG facility, the PSP Chief may issue a NOA.
- (b) The NOA shall be filed in a new proceeding and shall serve as notice from the Commission of the alleged inadequacies and to facilitate and expedite plan or procedure revision and implementation so that public safety is not compromised. The NOA shall:
  - (I) specify the alleged inadequacies and the proposed action(s) for revision of the plans and procedures;
  - (II) specify a proposed timeline for revised plan/procedure implementation based on the impact to public safety; and
  - (III) provide an opportunity for response.
- (c) Within 30 days after receipt of a NOA issued pursuant to the rule, unless a longer period is otherwise specified in the NOA or a different time period is agreed to mutually, an operator shall file in the proceeding its response with one of the following options.
  - (I) The operator may admit the NOA through the following filings and actions:
    - (A) the operator shall pay any proposed final civil penalty in full; and
    - (B) the operator shall agree to any proposed compliance directive.

- (II) The operator may request the Commission consider an offer in compromise to the NOA through the following filings and actions:
  - (A) the operator may request reconsideration and reissuance of the initial NOA through submittal of a written explanation, information, or other material in response to the allegations contained in the NOA; in objection to the proposed compliance directive; or in mitigation of the proposed final civil penalty; or
  - (B) the operator and the PSP Chief may jointly file a stipulation and settlement agreement pursuant to rule 11507, resolving the allegations in the NOA for the Commission's consideration.
- (III) The operator may oppose the NOA, or any part thereof. The operator shall file its response opposing the allegations in the NOA in the proceeding and provide all relevant information it finds addresses the issues raised. If an operator opposes any alleged violation in the NOA, the matter shall be set for hearing.
- (d) If the operator fails to respond as provided in this rule within 30 days of the NOA, the NOA shall be deemed opposed by the operator and shall be set for hearing as prescribed by subparagraph (c)(III) above.

**11507. Compliance Action – Hazardous Facilities Order (HFO).**

- (a) If an inspection, audit, investigation, or test reveals that the continued operation of a pipeline or LNG facility may pose a severe and imminent risk to public safety, as determined by current regulation, industry standard, or other relevant objective technical standard, the PSP Chief may consider the pipeline or LNG facility to be a hazardous facility and file a formal complaint with the Commission against the operator of the facility. The complaint shall allege facts sufficient to establish the existence of a hazardous facility and to support an HFO issued upon conclusion of a Commission proceeding, or, if justified, a summary HFO pursuant to paragraph (j) of this rule.
- (b) A formal complaint by PSP Staff shall be issued, and a hearing shall be conducted in accordance with the Commission's Rules of Practice and Procedure and Article 6 of Title 40, C.R.S.
- (c) Except as provided in paragraph (j) of this rule, if the Commission finds, after hearing, that a pipeline facility or a LNG facility is hazardous to life or property, the Commission shall issue an order directing the operator to take corrective action. Corrective action may include, without limitation, suspension or restriction of the use of the pipeline facility or LNG facility, physical inspection, testing, repair, or replacement.
- (d) In making a determination that a pipeline facility or a LNG facility is hazardous to life or property, the following shall be considered, as appropriate:
  - (I) the characteristics of the pipe used in the pipeline facility or the LNG facility involved, including (without limitation) its age; manufacturer; physical properties, including its resistance to corrosion and deterioration; and the method of its manufacture, construction or assembly;

- (II) the nature of the gas transported by the pipeline facility or the LNG facility, including its corrosive and deteriorative qualities; the sequence in which the gas is transported; and the pressure required for transportation of the gas;
  - (III) the characteristics of the areas in which the pipeline facility or the LNG facility is located, in particular the climatic and geotechnical or geologic conditions associated with the areas, the population, the population density, and the community growth patterns of the areas;
  - (IV) any recommendation of the NTSB issued in connection with any investigation conducted by that Board; and
  - (V) such other factors as may be relevant.
- (e) A Commission decision finding that a pipeline facility or a LNG facility is a hazardous facility shall contain a description of the corrective action required of the operator and the date by which the operator shall complete the ordered corrective action.
  - (f) The Commission shall dismiss the complaint if it determines that the pipeline facility or the LNG facility is not hazardous to life or property.
  - (g) Upon a showing that the ordered corrective action has been completed and has eliminated the condition(s) that made a pipeline facility or a LNG facility a severe and imminent risk to public safety, the Commission shall issue an order of satisfaction. Prior to issuing an order of satisfaction, the Commission may hold a hearing to determine whether the operator has completed the corrective action and whether the corrective action has eliminated the conditions(s) that made the pipeline facility or the LNG facility hazardous to life or property. The order of satisfaction shall be issued in the complaint docket in which the hazardous facilities order was entered.
  - (h) The Commission may bring a formal complaint alleging the existence of a hazardous facility supporting the issuance of an HFO and an NPV in the same proceeding, but is not required to do so.
  - (i) If the Commission determines that the delay inherent in holding a hearing may result in, and significantly increases the likelihood of, serious harm to life or property, the Commission may issue an expedited or summary HFO before holding a hearing. The provisions of paragraph (b) of this rule shall apply to a hearing held pursuant to this paragraph. The purpose of a hearing held pursuant to this paragraph is to determine whether the summary HFO should remain in effect, should be amended, or should be rescinded. The summary HFO shall include the following:
    - (I) the findings that support the determination that a summary HFO is appropriate;
    - (II) the corrective or remedial actions required of the operator; and
    - (III) a statement informing the operator of its right to a hearing, upon request, as soon as practicable after issuance of the order.



**11508. Consent Stipulations.**

- (a) If a matter has been set for hearing at any time before the issuance of a decision by the Commission, the PSP Chief and the operator may agree to dispose of the matter by a consent stipulation. The consent stipulation shall be submitted to the Commission for approval or rejection.
- (b) A consent stipulation executed under this rule shall include the following:
  - (I) an admission by the operator of facts;
  - (II) an express waiver by the operator of further procedural steps, including (without limitation) its right to a hearing; its right to seek judicial review, or otherwise to challenge or to contest the validity of the consent stipulation; and its right to seek judicial review of the Commission order accepting the consent stipulation;
  - (III) an acknowledgment by the operator that the NPV may be used to construe the terms of the consent stipulation; and
  - (IV) a statement of the actions that the operator will take and the date by which such actions shall be completed.
- (c) As appropriate, a consent stipulation executed under this rule may include a civil penalty.

**11509. Subpoenas.**

The Commission and Administrative Law Judge, or the Director may issue a subpoena in accordance with rule 1406 of the Commission's Rules of Practice and Procedure.

**11510. Injunctive Relief.**

The Commission may request that the Attorney General bring an action in an appropriate district court for injunctive or other relief as provided in Article 7 of Title 40, C.R.S. whenever the Commission is of the opinion that an operator has engaged in, is engaging in, is about to engage in, or willfully permits any act or practice that constitutes, a violation of 49 U.S.C. §§ 60101 et seq., these rules, or an order of the Commission.

**11511. – 11999. [Reserved].**

**GLOSSARY OF ACRONYMS**

C.F.R. - Code of Federal Regulations  
HFO - Hazardous Facilities Order  
LP - Liquid Petroleum  
LNG - Liquefied Natural Gas  
LPG - Liquid Petroleum Gas  
MMO - Master Meter Operator  
NFPA - National Fire Protection Association  
NOA - Notice of Amendment  
NPV - Notice of Probable Violation

NRC - National Response Center

P-DIMP - Prescriptive Distribution Integrity Management Program

PSP - Pipeline Safety Program (of the Colorado PUC)

PHMSA - U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration

RFA - Request for Amendment

RFI - Request for Information

SSAG - Single Structure Above Ground (gas pipeline system)

U.S.C. - United States Code